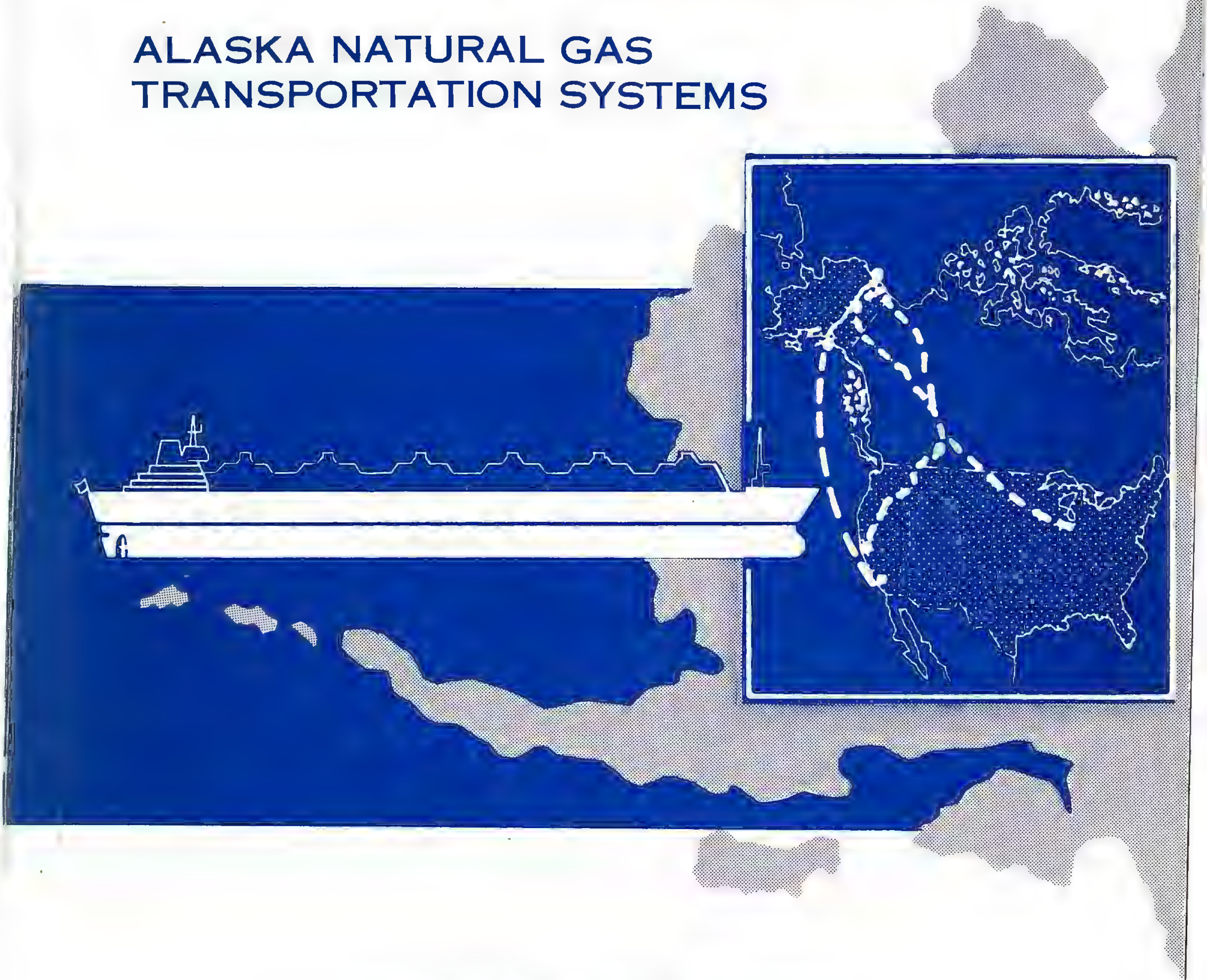
RECOMMENDATION TO THE PRESIDENT

ALASKA NATURAL GAS TRANSPORTATION SYSTEMS



UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

MAY 1, 1977

FEDERAL POWER COMMISSION
WASHINGTON, D.C. 20426

IN REPLY REFER TO:

May 2, 1977

The President
The White House
Washington, D. C. 20500

Dear Mr. President:

Enclosed is the recommendation of the Federal Power Commission pursuant to Section 5 of the Alaska Natural Gas Transportation Act of 1976. We have come to the following basic conclusions:

1. It is in the best interests of the citizens of the United States that a system be built in the near future to transport natural gas from the North Slope of Alaska to the contiguous United States.

2. Three competing groups have applied for a certificate of public convenience and necessity to construct and operate such a system. They are the Alaskan Arctic Gas Pipeline Company, El Paso Alaska Company, and Alcan Pipeline Company. The first and third applicants propose overland systems, while the second is a pipeline and tanker route.

3. We recommend that an overland system through Canada be selected, if such a route is made available by the Government of Canada on acceptable terms and conditions. If appropriate, discussions could be undertaken after the completion of proceedings before their National Energy Board. Until the Canadian Government has made a decision whether a land route is available, it would be premature for this Commission to recommend a route, unconditionally.

The President May 2, 1977

4. In making a decision between the two overland routes, it will become obvious to the reader of this recommendation that additional information is needed as well as an understanding of the intentions of the Government of Canada. Based on today's circumstances, reasonable men can disagree on the right course of action. Under present circumstances and expectations, Chairman Dunham recommends Alcan, Commissioner Watt Alcan, Commissioner Holloman Arctic, Commissioner Smith Arctic.

Commissioners Holloman and Smith recommend that an overland system through Canada be selected. Section 5(d) of the Alaska Natural Gas Transportation Act precludes the Commission from basing its recommendation upon the fact that Canadian authorities have not at this time rendered a decision authorizing a pipeline system to transport Alaskan natural gas through Canada. They, therefore, recommend approval of the Arctic proposal, conditioned upon timely affirmative decisions by the Government of Canada to make the route available and, after development, to allow simultaneous transportation of Canadian natural gas reserves from the Mackenzie Delta. In the absence of a Canadian determination that development and transportation of Mackenzie reserves should be permitted, the Alcan project should be approved, subject to the Government of Canada's making the route available on acceptable terms and conditions. In the absence of timely and acceptable agreements with the Canadian Government to make a route available for an overland system, a United States pipeline and tanker system can be built and can deliver gas to the contiguous United States at an economical price, and the El Paso project should be selected.

5. In the absence of agreement with the Canadian Government, a United States pipeline can be built in Alaska and a tanker system can deliver the gas to the contiguous United States at an economical price.

6. Any of the proposed systems can be financed without extraordinary risk-bearing by consumers or taxpayers, if investors are allowed the opportunity to earn an adequate return commensurate with the unusual size and degree of risk in this project. Alternatively, consumers and taxpayers could assume the risks of noncompletion of the system or interruption of service in return for a lower delivered cost of gas.

In reaching these conclusions, we have exhaustively considered the massive record compiled here and material outside the record, as directed by the Alaska Natural Gas Transportation Act. Our full recommendation covers hundreds of points. In the last analysis, we find the following items to be the most important and we recommend that you and the Congress direct your attention primarily to the confirmation or modification of these conclusions.

A. At least 20 trillion cubic feet of producible natural gas exist at Prudhoe Bay in Alaska, enough to provide about five percent of our natural gas consumption for the next 25 years. These volumes are adequate to support an economical transportation system.

B. This gas must be produced and delivered to markets both for its own value as energy and because its extraction is necessary to avoid a long-term reduction in oil production from Prudhoe Bay.

C. This gas can be delivered to the contiguous United States and successfully marketed by any one of the three competing applicant groups: Arctic, Alcan and El Paso.

D. Each system will have some adverse environmental impacts. We believe all of these impacts to be acceptable, given proper precautionary measures. Arctic would involve crossing the Arctic National Wildlife Range, and other lands now little used by man. The other projects would generally follow existing utility corridors - a distinct environmental advantage.

E. An overland route can deliver each unit of gas more cheaply than a land and water route using liquefied natural gas technology. If Canadian gas is also developed, the sharing of facilities will lower Arctic's cost of servi to Americans slightly below that of Alcan.

F. Calculations of Net National Economic Benefit produce the same relative results for the three systems. El Paso has an advantage in this analysis, because all of its tax payments go to the United States, and virtually all of its wage and material payments go to Americans.

G. Using our best estimate of the likely ultimate construction cost (not the applicants' figures), El Paso's system would require the least capital, with Alcan and Arctic costing somewhat more.

H. Arctic has the greatest risk of major cost overruns beyond our estimate, primarily because of its difficult winter construction schedule. El Paso is least vulnerable to such overruns.

I. Each of the systems can be constructed basically in the manner proposed, with the qualifications and conditions contained in our report.

J. Each of the systems should operate reliably once service begins. El Paso has a slightly higher likelihood of service interruption due to its complex nature and greater seismic risk.

K. El Paso would be the easiest system to finance because of its slightly lower initial cost and because of Federal guarantees of bonds for its tankers under Title XI of the Merchant Marine Act.

L. All of the above cost conclusions assume the simultaneous development and transportation of Canadian reserves in the Mackenzie Delta. Arctic's proposed route has the advantage of passing directly through this area. Should the Canadian Government decide not to proceed with the development of those reserves at this time, the overall balance of cost advantages shifts to Alcan.

M. Should additional gas be found in the vicinity of the transportation system, expansion capability could become important. Arctic can expand to deliver up to 3.5 billion cubic feet per day (Bcfd) from Prudhoe Bay, at a small cost. Any such expansion would lower the unit cost of gas delivered. Alcan is designed to start at 2.4 Bcfd, but can expand to 3.2 Bcfd at a small additional cost. El Paso can also expand its pipeline deliveries to 3.2 Bcfd at low cost, but its costs for ships, terminal facilities, and operating expenses will rise more rapidly proportionate to increased deliveries.

N. The North Slope gas should be distributed as widely as possible throughout the United States. Wide distribution will encourage broad-based financing for the chosen project, an important consideration in an undertaking of this size. Furthermore, because there is always some threat of service interruption, no area of the country should be allowed to become too heavily dependent on the Alaskan gas.

O. A choice must be made as to who shall bear the ultimate risks of project failure, service interruption, or massive cost overruns. If investors are to bear them, they will expect a commensurate return. If they do not receive such a return, the project cannot be privately financed. If consumers or taxpayers bear the risks, their charges, in the event of success, should be lowered in return for the service they have rendered. Our recommendation outlines the dimensions of each plan and contains specific suggestions for implementing either approach.

The President May 2, 1977

The decision now before you, we recognize, will significantly influence this nation's energy future. Therefore, beyond providing our best thinking in these recommendations, the commissioners and staff of the Federal Power Commission stand ready to assist you in every way.

Sincerely yours,

Richard L. Dunham
Chairman

James G. Watt
Vice Chairman

Don S. Smith
Commissioner

John H. Holloman III
Commissioner

RECOMMENDATION TO THE PRESIDENT

ALASKA NATURAL GAS TRANSPORTATION SYSTEMS

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

MAY 1, 1977

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CHAPTER I

SUMMARY

A. Introduction

In 1976, Congress enacted the Alaska Natural Gas Transportation Act to expedite construction of a system for transporting Alaskan natural gas to United States markets by the soundest route in terms of the Nation's economic, national security and environmental interests. The unprecedented discoveries of gas in Alaska's North Slope can significantly increase the supply of natural gas, which is crucial to this Nation's economy and well-being.

The Act marked a major departure from usual practice. Ordinarily, the Federal Power Commission has the final approval authority over proposed natural gas transmission systems. Because of the magnitude and international ramifications of creating an Alaskan natural gas transmission system, the Act was passed in order to allow the President and the Congress to participate in the final decision and expedite the construction and delivery of gas. The Federal Power Commission is charged under the 1976 Act to report to the President by May 1, 1977, its recommendation concerning the selection of a transportation system. The Commission is charged, in addition, to setting forth the bases for its decision in terms of projected costs, gas supply and demand, financing proposals, environmental impact and other relevant factors.

Natural gas makes up a critical component of America's total energy supply. From 18 percent in 1950, it now provides roughly a third of all energy consumed in the country. The fuel is vital to the operation of our industries, our homes and our farms. When shortages of natural gas occur, as during the severe winter of 1976-77, the effects are profound hardship and danger for individuals and substantial economic disruption for the country.

Although there is an urgent necessity to conserve energy, to harness solar energy, to make fuller use of coal and safe nuclear power, the fact is inescapable that for the foreseeable future, the United States must depend on a large, stable supply of natural gas as well. The construction of an economically and environmentally sound Alaskan natural gas pipeline can reduce this Nation's energy vulnerability and provide greater energy independence.

This report, the result of two years of hearings and studies, transmits to the President the Commission's recommendation for achieving that objective under the Alaska Natural Gas Act of 1976.

B. Potential Reserves

The Prudhoe Bay field, discovered in 1968, offers a major source of natural gas. It contains the largest petroleum accumulation yet discovered on the North American continent. The amount of saleable gas is estimated to exceed 20 trillion cubic feet (Tcf). 1/ If total natural gas consumption remains at its present level for the next 25 years, the proven Prudhoe Bay reserves alone could provide approximately five percent of that volume. Other undiscovered reserves are possible elsewhere in Alaska, particularly on the North Slope and in the Beaufort Sea.

Production of oil at Prudhoe Bay will begin later this year. The production plan recently filed with the State of Alaska provides during the first years of operation for reinjecting the natural gas produced along with the oil into the reservoir in order to maintain field pressure. After four to five years natural gas can be produced for sale.

1/ Some of the gas is segregated in a gas cap and some of it is in solution with oil. There are in excess of 9 billion barrels of recoverable oil.

C. Applicants For The Project

1. Alaskan Arctic Gas Pipeline Company

The first applicant to the FPC for a certificate of convenience and necessity to transport Alaskan natural gas was a consortium of American and Canadian natural gas pipeline companies, Alaskan Arctic Gas Pipeline Company (Arctic) which filed with the Commission on March 21, 1974. 2/ Arctic Gas proposes a wholly overland route. The pipeline would traverse the north coast of Alaska and the Yukon Territory, to the Mackenzie Delta, then head southeasterly along the Mackenzie River into Alberta, to Caroline Junction. There it would divide into an "eastern" and "western" leg. The eastern leg would continue to Monchy, Saskatchewan; there is would connect with the proposed Northern Border system which would carry the gas to Dwight, Illinois, with intermittent take-off points. The western leg would enter the United States at Kingsgate, B. C., and continue to Antioch California; the United States portion of this segment would be constructed by Pacific Gas Transmission Company and the Pacific Gas and Electric Company. Arctic's pipeline is also designed to transport Canadian Mackenzie Delta gas and future Beaufort Sea gas to Canadian markets. (See Exhibit I-1.)

2/ As finally constituted, this group includes principal applicants Canadian Arctic Company Ltd. and Alberta Natural Gas Company Ltd. (applicants before the National Energy Board of Canada), Alaskan Arctic, Northern Border Pipeline Company (a partnership of six United States natural gas transmission companies), Pacific Gas Transmission Company, and Pacific Gas and Electric Company. The original group also included the principal producers.

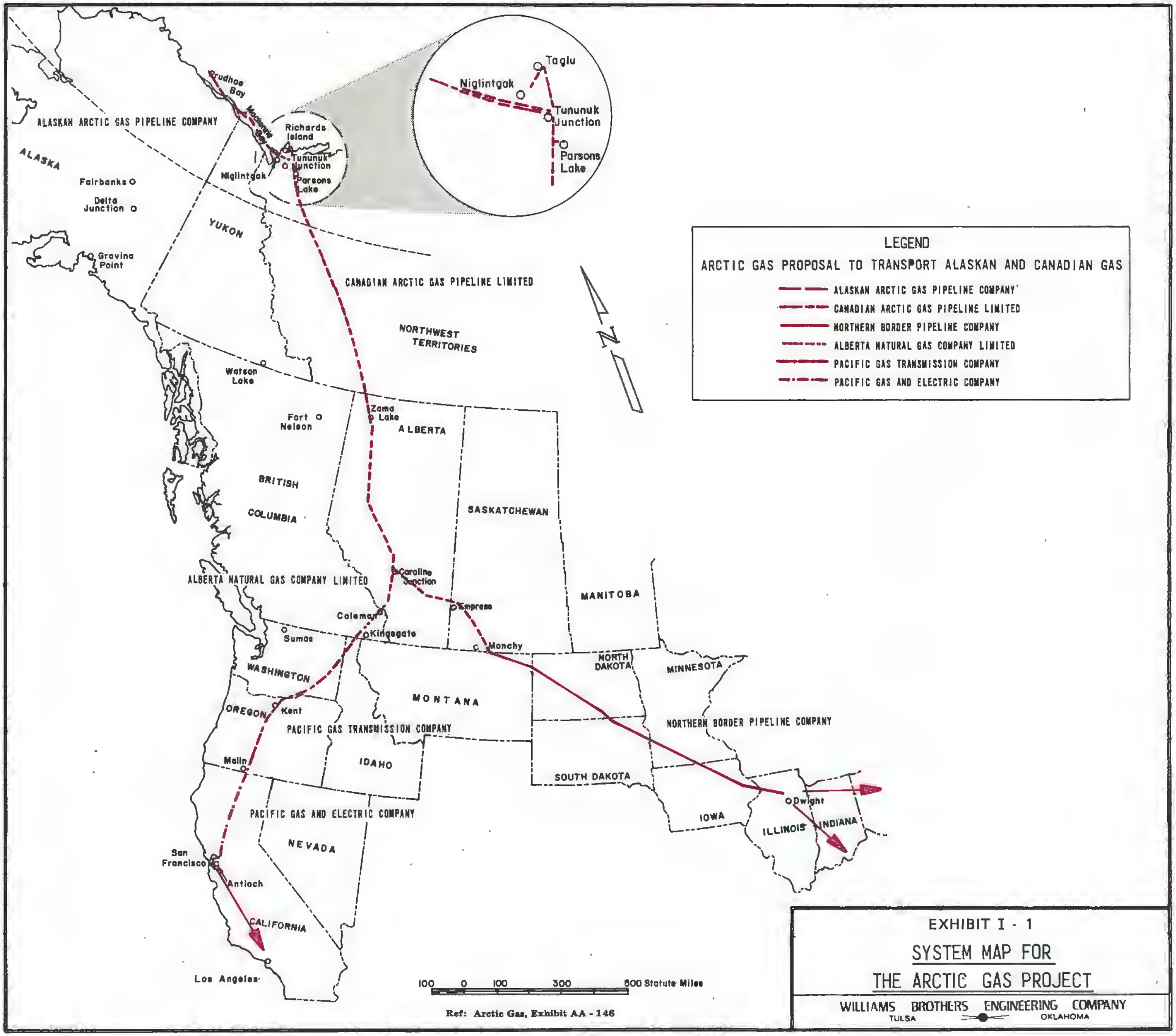

EXHIBIT I - 1

SYSTEM MAP FOR THE ARCTIC GAS PROJECT

WILLIAMS BROTHERS ENGINEERING COMPANY
TULSA OKLAHOMA

2. El Paso Company

On September 24, 1974, El Paso Alaska Company (El Paso) filed an application for a second transportation system. 3/ El Paso would transport only Alaskan gas by a pipeline which would generally follow the route of the Alyeska oil pipeline to a point north of Valdez and then to a warm water port at Gravina Point on Prince William Sound, Alaska. The natural gas would be liquefied and a fleet of liquefied natural gas (LNG) tankers would transport it to a California terminal and regasification plant. After regasification, the gas would be transported by pipeline and by displacement to natural gas consumers throughout the United States. 4/ (See Exhibit I-2.)

3. Alcan Pipeline Company and Northwest Pipeline Company

On July 9, 1976, Alcan Pipeline Company and Northwest Pipeline Company (Alcan) filed a third application for a certificate, covering a route across Alaska following the Alyeska pipeline route to Fairbanks, Alaska, then along the Alcan Highway to the Alaska-Yukon border. 5/ The route goes through Canada along the Yukon-British Columbia border, then south using in part existing Canadian gas pipelines in British Columbia and Alberta, and then to the U. S. border,

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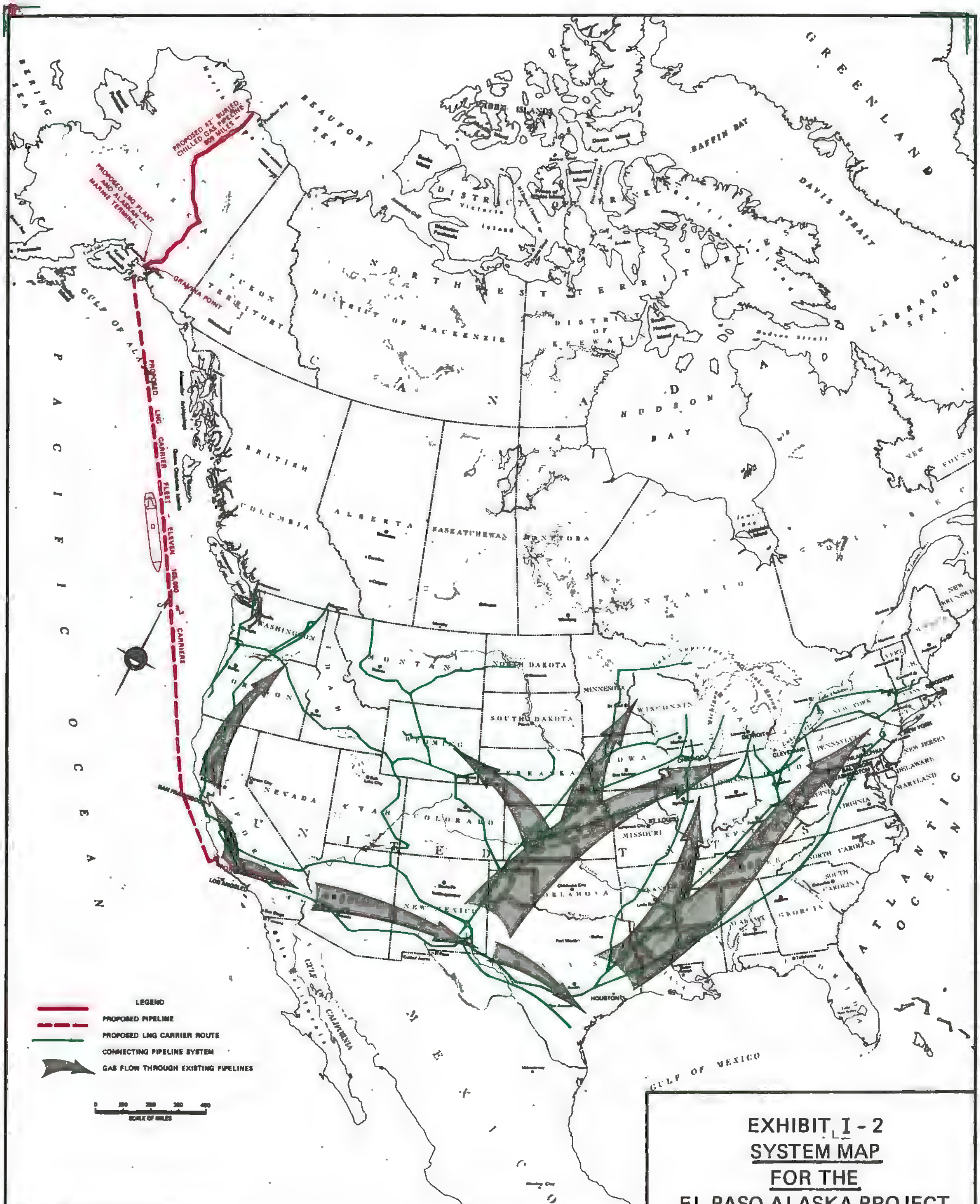
3/ Other companies involved are Western LNG Company and El Paso Natural Gas Company.

4/ Displacement is a method of distribution whereby natural gas may be supplied from a closer point in exchange for gas elsewhere. Such procedures avoid the transportation costs of physically transferring gas between markets.

5/ The companies directly involved are Alcan Pipeline Company (Alaska), Foothills Pipelines (Yukon) Ltd., Westcoast Transmission Company Ltd., Alberta Gas Trunk Line (Canada) Ltd. and, by adoption, Northern Border Pipeline Company, Pacific Gas Transmission Company, and Pacific Gas and Electric Company.



Ref: El Paso Filing; Fig. 1.0 - 1

EXHIBIT I - 2
SYSTEM MAP
FOR THE
EL PASO ALASKA PROJECT

connecting to the west with Northwest Pipeline near Sumas, Washington, and PGT at Kingsgate, British Columbia. Gas would move east through new facilities to Monchy, Saskatchewan. This application assumes that Northern Border, an applicant in the Arctic Gas project, would receive the gas at Monchy and distribute it to the Midwest and East.

On March 8, 1977, Alcan filed an alternate proposal which follows essentially the same route as the original proposal 6/ but consists of an all new pipeline with no commingled Canadian gas. The proposed route south of Caroline Junction, Alberta, is essentially the same as that proposed by Arctic. (See Exhibit I-3.) In oral argument before the Commission in early April, Alcan stated that the alternate proposal is to be regarded as their primary proposal. Since the alternate does not have a significantly different environmental impact, avoids cost-sharing issues expressed by some critics, and has superior economic characteristics (lower cost of service, better expansibility, and higher net national economic benefit), we deem the alternate proposal to be clearly preferable to the initial Alcan system. Therefore, the Alcan proposal discussed herein shall be the alternate proposal, unless otherwise specified.

Hence, at this time, we have considered three alternate systems for the transportation of Alaskan natural gas: one by sea and two by land. Each system is described in greater detail in Chapter II.

6/ New routing is provided for about 500 miles in British Columbia and Alberta.

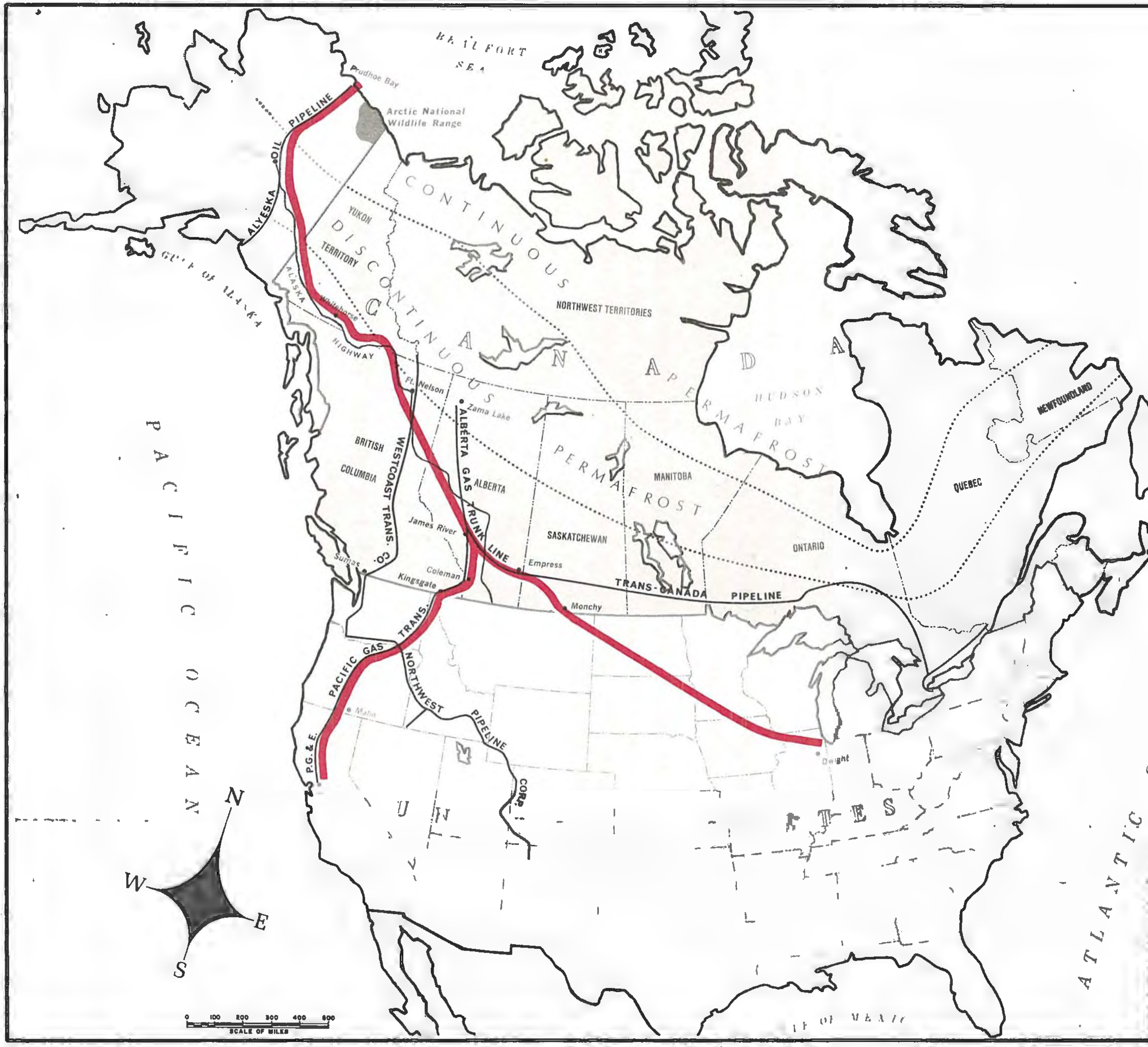


EXHIBIT I – 3

SYSTEM MAP FOR THE ALCAN PIPELINE PROJECT (48" ALTERNATIVE)

Ref: March 8, 1977 Filing By Alcan

D. The Initial Hearing

Pursuant to a Commission order of January 23, 1975, the hearing to develop evidence on the competing applications commenced on April 7, 1975. That hearing was conducted before Administrative Law Judge Nahum Litt for 252 days. The total record consists of 253 volumes of transcripts, almost 45,000 pages, about 1,000 exhibits (some, such as the environmental impact statements, running more than 1,000 pages each), and enumerable items by reference. Judge Litt's initial decision, issued February 1, 1977, is 430 pages long with an additional 200 pages of appendices.

E. Requirements Under The Act

The Alaska Natural Gas Transportation Act of 1976 was enacted on October 2. That Act required the earliest practicable suspension of the usual certificate proceedings under the Natural Gas Act and further required the Federal Power Commission to present to the President on or before May 1, 1977, a recommendation regarding the transportation of Alaskan natural gas to the lower 48 states. By Order No. 558, the suspension was effective upon the filing of Judge Litt's initial decision. Since that time, the Commission has (1) received briefs on exceptions from Staff, the applicants and other parties, (2) permitted the filing of supplementary information (see Commission Order No. 558-C), (3) allowed interrogatories and responses (see Commission Order No. 558-E), and (4) heard four days of oral argument (see Commission Order No. 558-D). 7/ Finally, the Commission, through its "delegates" (See Commission Order No. 558-A), has worked with numerous Federal Government agencies to obtain the most recent information on several aspects of this recommendation.

7/ Some unsolicited opinions and "evidence" were also received by the Commission. This material was not examined or considered, in accordance with Commission Order No. 558-C.

The function of the Commission under the Alaska Natural Gas Transportation Act differs from the usual quasi-judicial role of the Commission. In making this recommendation, we are acting as advisors to the President. We, therefore, believe our principal role is to set forth the strengths and weaknesses of the various options. We hope that our recommendation will have influence in the ensuing decision process, but realize that many of the crucial factors are beyond our authority or control.

We believe that our recommendations are practical and fully supported by the record and evidence available at this time.

F. Economic Analysis

The most important finding is that it is in the best interest of the citizens of the United States to build a transportation system for Alaskan natural gas. 8/ Regardless of which of the three competing systems is eventually chosen (and we do not believe any other systems are likely to be preferable to these three), the benefits of Alaskan gas fully justify the costs and risks involved. While the capital employed in building a transportation system might be used elsewhere in our economy, it would not be likely to produce more positive results in terms of cheaper energy, more jobs, and economic stimulation, both in Alaska and throughout the country.

1. Net National Economic Benefit Analysis

The cornerstone of this conclusion is net national economic benefits (NNEB) that would be gained under any

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8/ See Exhibit I-4 which depicts the importance of natural gas in our economy over the past two and one-half decades.

EXHIBIT I-4

ENERGY CONSUMPTION PER CAPITA IN THE UNITED STATES, 1950 - 1975[a]

Year	Total Energy Consumed (Trillions of Btu)	Natural Gas Consumed (Trillions of Btu)	Resident Population (Thousands)	Total Energy Per Capita (Millions of Btu)	Natural Gas Per Capita (Millions of Btu)	Relative Importance of Natural Gas (%)
1950	34,153	6,150	151,241	226	41	18.0
1951	36,913	7,248	153,307	241	47	19.6
1952	36,576	7,760	155,680	235	50	21.2
1953	37,697	8,156	158,235	238	52	21.6
1954	36,360	8,554	161,161	226	53	23.5
1955	39.956	9,232	164,309	243	56	23.1
1956	42,007	9.834	167,310	251	59	23.4
1957	41.920	10,416	170,375	246	61	24.8
1958	41,493	10,995	173.332	239	63	26.4
1959	43,507	11,991	177,135	246	68	27.5
1960	44,816	12,736	179,992	249	71	28.4
1961	45,573	13,228	183,057	249	72	29.0
1962	47,620	14,027	185,890	256	75	29.4
1963	49,649	14,843	188,658	263	79	29.8
1964	51,554	15,515	191,372	269	81	30.0
1965	53,969	16,097	193,815	278	83	29.8
1966	56,412	17,393	195,936	288	89	30.8
1967	58,265	18,250	197,859	294	92	31.3
1968	61,763	19,580	199,846	309	98	31.7
1969	64,979	21,020	201,423	323	104	32.3
1970	67,143	22,029	203,185	330	108	32.8
1971	68,698	22,819	207,203	332	110	33.2
1972	72,108	23,125	208,969	345	111	32.0
1973	74,743	22,712	209,844	356	108	30.3
1974	72,880	21,733	211,389	344	102	29.8
1975p	71,078	20,173	213,137	333	94	28.3

a - Alaska and Hawaii included subsequent to 1958.

p - Preliminary

Sources: U.S. Bureau of Mines, and U.S. Bureau of the Census.

one of the three systems. The NNEB for each system is defined as the present value of the total social benefits to be obtained by the project, less the total costs. Studies in the record and further analyses indicate that the NNEB for each of the three systems would be positive even if substantial cost overruns, construction delays or a reduction in value of the gas occurred. Furthermore, since the NNEB derived herein is based solely upon the value of proven natural gas reserves, any future discoveries on the North Slope can only increase the NNEB of any of the projects. These NNEB studies are summarized in Exhibit I-5 and discussed in more detail in Chapter IV.

EXHIBIT I-5

Summary of NNEB and Cost of Service

	Net National Economic Benefit (1975 $ Billions)			20-Year Average Cost of Service (1975 $/Mcf)
	Gross Benefit	Cost	NNEB	
Arctic	22.06	6.91	15.15	$ 0.76
El Paso	20.32	7.46	12.86	1.09
Alcan	22.89	7.23	15.66	0.79

Sources: Exhibits IV-4 and IV-5.

The only benefit considered in determining the NNEB was the savings from lower consumption of alternative fuels. A less tangible, yet equally important benefit of Alaskan natural gas is reduced dependence on foreign energy imports. Our Nation's bargaining power in the world energy market is improved by our ability to draw on domestic energy resources. 9/ An Alaskan transportation system provides additional diversity in our portfolio of energy supplies, one that is relatively independent of other sources. Alaskan gas will not only provide increased energy but add bargaining power that can be used to obtain other supplies and to lower costs for all energy.

One of the proposed sponsors argued that the stimulative effects on employment should also be considered in the NNEB. On that factor along, El Paso would have the largest impact since it would employ only United States labor, build its ships in United States yards, and probably buy United States pipe and other materials. The other systems would stimulate the Canadian economy as well as the United States. We are reluctant to place much weight on the Alaskan pipeline as an economic stimulus. As detailed in Chapter IV, economic stimulation could be achieved by other means. But, since these alternative means may not materalize, El Paso's effect on the economy should not be totally ignored.

In computing the final NNEB, United States taxes have been treated as transfer payments and are excluded from the calculation. Canadian taxes are included as a cost. Since both Alcan and Arctic would pay substantial Canadian taxes, while El Paso would pay none, this offsets in part the greater fuel consumption by El Paso and the resultant NNEB

9/ Department of the Interior (DOI) and Arctic Gas following the lead of DOI, both included in their benefit calculation an item entitled "Benefit of Energy Independence," based upon the assumption that 1 Btu of delivered Alaskan gas reduced our need to stockpile oil by 1 Btu, saving the cost of both the oil and the related storage facilities. We believe this number is so arbitrary that it is meaningless and that the benefit we are discussing herein goes beyond simple storage impacts of reduced dependence.

of all three systems is quite close. From a social perspective, there is not a large difference between the systems, but El Paso would have a somewhat lower net benefit. This is due to its higher operating costs and lower fuel efficiency.

The most important conclusion from this NNEB study is that all the systems have expected benefits that exceed their expected costs by a great margin and therefore have great capacity to absorb cost overruns while still providing positive net benefits.

2. Cost of Service

Exhibit I-5 also displays the 20-year average transportation costs (cost-of-service) for the three systems.

These costs of service indicate an important fact: all of the systems can deliver the Alaskan gas at a reasonable cost to the consumer. Even El Paso could deliver gas at an average price of less then $2.10 per MMBtu, assuming a field price of $1.00 per MMBtu. We have no doubt that the gas is worth much more than this. Even with extremely large cost overruns, there is no significant marketability risk for this gas.

G. Gas Reserves and Deliverability

1. Alaska

The determination of the natural gas reserves from the northern part of Alaska is critical to whether a transportation system should be constructed and what its capacity should be.

As detailed in Chapter III, the Prudhoe Bay Oil Pool is the principal source of Prudhoe Bay gas. Adjusting for a recovery efficiency of 75 to 80 percent and a 26 percent shrinkage factor (CO_2 removal, field use, and gas conditioning), the recoverable gas from 40 Tcf in-place is 22.2 to 23.7 Tcf. Most studies conclude, and the producers' recent reservoir management plan states, that sales of at least 2.0 Bcfd can be made without adversely affecting the ultimate recovery of oil and gas from the field. The producers have indicated that it might be possible to increase gas deliveries to 2.5 Bcfd. These deliverability figures related to the Main Area Sadlerochit reservoir only. The West Area (Eileen Area) will be developed later and some small additional amounts of gas might be available from other reservoirs in the Prudhoe Bay area.

Much less is known about gas reserves in Naval Petroleum Reserve No. 4 (NPR-4) which encompasses approximately 37,000 square miles located in the northwestern portion of the North Slope. (See Exhibit II-1.) While potential reserve estimates in NPR-4 have ranged from 5 Tcf to 78.6 Tcf, gas is not now available currently is sufficient quantities in NPR-4 to justify its connection to any of the proposed transportation systems. The most realistic NPR-4 resource estimate now available to the FPC is about 14 Tcf, and the maximum saleable gas volumes could range from 0.3 to 0.9 Bcfd. The upper end of the range is highly speculative, given the likelihood that the reserves in this region will be in small, widely-scattered fields. Thus, the possibility of significant supplies from NPR-4 appears slight.

Geological and limited geophysical information has suggested the possibility of substantial gas reserves under the Arctic National Wildlife Range (ANWR). Drilling activity has not been permitted. No credible resource estimate can be made at this time, but the area is considered to have a high resource potential.

Similarly, high resource potential exists for the Beaufort Sea (north of the Prudhoe Bay Field) and, to a lesser extent, the Chukchi Sea (west of NPR-4). The interior basins of Alaska hold little promise of natural gas.

Thus, we conclude that it is reasonable to assume 2.0 to 2.5 Bcfd from Prudhoe Bay Oil Pool within five years after the commencement of oil production. There exists some possibility of increased delivery from the North Slope of perhaps as much as an additional 1.5 Bcfd, (from NPR-4, ANWR, and the Beaufort Sea as well as other reservoirs in or near the Prudhoe Bay Oil Field). Thus, we find the system should be designed to carry initially 2.0 to 2.5 Bcfd, and be capable of expansion to an additional 1.0-1.5 Bcfd. As described in Chapter II, each of the systems is so designed.

2. Mackenzie Delta Area

Twelve fields have been established in the Mackenzie Delta area. Three major fields contain 3, 1.5 and 1.0 Tcf of reserves, respectively, including proved, probable and possible reserves. No other field exceeds of 0.4 Tcf total reserves by any estimate. Since the best onshore prospects probably have been drilled and since offshore prospects are highly speculative and expensive, it is likely that the current estimate of 6-7 Tcf of total reserves will not increase significantly in the near future.

While Arctic has projected that Mackenzie Delta reserves might grow to support up to 2.25 Bcfd deliverability, we believe it unlikely that deliverability will exceed 1.0 Bcfd in the near term. Proved reserves would have to more than double in order to sustain a deliverability of 1.0 Bcfd for 30-years. Recent drilling experience tended to increase proved reserves, but little was added to total reserves. This casts further doubt on the ability of this area to sustain a deliverability much in excess of 1 Bcfd.

Thus, we find that Mackenzie Delta deliveries of 1.0 Bcfd are a reasonable base case and 1.5 Bcfd is a reasonable upper limit. Arctic's 2.25 Bcfd appears excessive at this time.

H. Expansibility

1. Costs and Limits of Expansibility

Arctic and Alcan can expand the flow rate above the expected 2.25 Bcfd from Prudhoe Bay by adding compression. Arctic can transport up to 4.5 Bcfd. With an initial 2.25 Bcfd from Alaska and an estimated 1.0 Bcfd from the Mackenzie Delta, the Arctic system can carry an additional 1.25 Bcfd from Alaska (or 0.75 Bcfd if Mackenzie expands to 1.5 Bcfd). This expansion would require an 11 percent increase in capital costs for additional compression and some increase in operating fuel requirements. If Mackenzie Delta reserves prove larger than currently anticipated, and their deliverability is higher than the 1 Bcfd, less capacity would be available to carry Alaskan gas. Looping, 10/ though more expensive, could further increase overall capacity for both Alaskan and Mackenzie Delta gas.

The Alcan system can be expanded at low cost from 2.40 Bcfd to 3.4 Bcfd for Alaskan gas by slightly more than doubling compression, which would add about 12 percent to total capital costs and increase fuel cost requirements. Such an expansion would actually lower unit costs since the expansion adds more than 50 percent to the flow rate. Expansion beyond this extent would require looping.

El Paso's overland pipeline expansibility can be increased from its designed 2.4 Bcfd to 3.2 Bcfd with the addition of compression and some loss in efficiency. But El Paso also requires additional LNG trains, ships and more time. Thus, the LNG part of the El Paso system enjoys no economies of scale comparable to the other two systems. El Paso's LNG plant and ship costs make up approximately 50 percent of the system's total capital costs. On expansibility grounds, the El Paso system is inferior to either

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10/ Looping consists of paralleling an existing system with new pipeline along all or a portion of the existing line.

Alcan or Arctic. Chapter II discusses the methods of expanding the capacity of each of the systems.

Another consideration is the cost of connecting other producing regions into the proposed transportation systems. All three systems have more or less equal access to NPR-4 and Beaufort Sea reserves. Alcan and El Paso could more readily transport natural gas from the three interior Alaska basins south of the Brooks Range. However, there is little resource potential from these areas. Arctic could more readily transport natural gas from areas east of Prudhoe Bay, including The Arctic National Wildlife Range.

2. The Western Leg

Section 5(b)(1) of the Alaska Natural Gas Transportation Act requires that:

> "Any recommendation that the President approve a particular transportation system shall . . . include provision for new facilities to the extent necessary to assure direct pipeline delivery of Alaska natural gas contemporaneously to points both east and west of the Rocky Mountains in the lower continental United States." (Emphasis added.)

Staff argued before the Commission that the western leg will not be needed. Alcan, in oral argument, expressed the belief that the expansion decision could be delayed until further information is available. Arctic and the State of California, on the other hand, argued that the new western leg expansion facilities should be certified immediately to ease financing, make gas accessible to the West, and to stimulate imports. 11/

11/ It has been estimated that excess capacity might cost western users as much as 9¢ per Mcf of Alaskan gas delivered to the West if Canadian imports decline. California has stated it is willing to pay this amount in return for direct access to Alaskan and Canadian gas.

We recognize the Congressional mandate for contemporaneous delivery of Alaska natural gas both east and west of the Rocky Mountains. However, at this time we do not believe it necessary to reach a final decision as to what new facilities would be required to deliver Alaskan gas to the western states. No contracts have yet been executed to determine what quantities of gas will be sold to the western states. Further, the proposed western leg would consist of looping an existing system from Caroline Junction to San Francisco. (See Exhibits IX-1, IX-2 and IX-3). Existing facilities have a capacity to transport 980 MMcfd. With Canadian import contracts due to expire at various times throughout the 1980's, the possibility exists that at least 745 MMcfd of the Alaskan gas supplies could be delivered to the western states by the mid-1980's through existing facilities. 12/

While we hope that Canadian exports will not decline, and that more Canadian gas will be made available, we cannot currently judge the likelihood of this occurring. Thus, finding new facilities to be in the public interest would be premature at this time.

Fortunately, a judgment at this time is unnecessary. A decision on new western leg transmission facilities is not needed until approximately three years before scheduled gas delivery. This delay will provide time to assess the Canadian export situation and to ascertain what volumes have been contracted for sale to the western states and whether new facilities are required.

This issue is discussed in greater detail in Chapter IX.

12/ Export licenses authorizing gas exports of 140 MMcfd, 185 MMcfd, and 420 MMcfd are due to expire December 1981, October 1985, and October 1986, respectively. Other export licenses are due to expire on later dates. (See Exhibit IX-13.)

3. Alternative Uses of the Systems

The Alaska Natural Gas Transportation Act also requires the Commission to assess the potential of proposed systems to transport natural gas from other areas in addition to the Prudhoe Bay Field and to determine other uses for the system. Since pipelines have an expected life of about 50 years, and since the Prudhoe Bay reserves will produce from 25 to 35 years, this is an appropriate inquiry.

Since all three pipelines are buried underground in permafrost, they are not designed to carry liquids. Thus, while more than seven percent of total U.S. coal reserves lie in the Northern Field of Alaska, only by gasification could the energy from coal be transported by any of the three systems. 13/ While coal gasification is conceivable, it is far too early to speculate on the cost and the availability of water required by the process.

If Prudhoe Bay deliverability should fall below 2.25 Bcfd, at least a fraction of the El Paso investment could be employed elsewhere by redeploying the tanker fleet to transport LNG elsewhere, possibly from South Alaska or Indonesia to the West Coast. These tankers, however, have an expected life far shorter than pipeline facilities.

The southern portions of both Alcan and Arctic could transport natural gas from fields in Alberta and elsewhere along their route. Proved reserves in Alberta are estimated at approximately 45 Tcf and current production is about two Tcf per year. Thus, more reserves would have to be discovered before higher production rates could be sustained and the pipeline capacity used. The Northern Border component of either Alcan or Arctic could carry SNG from coal gasification plants constructed along its path in Montana and the Dakotas.

13/ See Multimodal Transportation and Utility Corridor Systems in Alaska, U.S. Department of the Interior, October 1974, pp. 46-47. The report considers trains and slurry pipelines, but the latter would have to be above ground and heated.

I. Environmental Impacts

Adverse environmental impacts can be ameliorated by careful alignment of pipeline facilities, siting of LNG and shipping facilities, the choice of construction modes and scheduling, and by sensitivity and caution in the construction and maintenance of the system. We believe all applicants have demonstrated their technical ability and determination to reduce to acceptable levels environmental impacts such as:

(1) vegetation and vegetative mat compaction during construction;

(2) slope failure (slides, erosion) and irregular topography (ruts and sunken trenches) resulting from breakdown of the permafrost regime;

(3) intrusion into wildlife activities, including the breeding and habits of caribou, musk ox, polar and grizzly bears, wolf, wolverine, fish, geese, dall sheep, eagles, falcon, deer, and moose; and

(4) siltation from river crossing, water withdrawal for snow roads, and gravel-gathering activities.

We will not attempt to summarize all these issues and the mitigative measures proposed by the applicant. The environmental impact of the projects is discussed in detail in Chapter V. However, we are confident that the measures proposed, together with proper conditions placed upon the successful applicant, and subsequent monitoring by the Federal inspector which the Act requires, will all provide adequate protection of the environment.

1. Arctic National Wildlife Range

However, some questions have been raised and must be answered, regarding the adequacy and feasibility of certain measures proposed to ease environmental impact. Some of the questions involve the Arctic National Wildlife Range (ANWR).

Only one of the proposed systems, Arctic Gas, crosses the Arctic National Wildlife Range, an area of roughly 14,000 square miles located in the northeast corner of Alaska. 14/

Public Land Order 2214 established the Arctic National Wildlife Range "for the purpose of preserving unique wildlife, wilderness and recreational values," and the land was "withdrawn from all forms of appropriations under the public land laws, including the mining but not the mineral leasing law, . . . and reserved for use of the United States Fish and Wildlife Service." (Emphasis added.) 25 F.R. 12598. Mineral leasing laws provide for pipeline rights-of-way and hydrocarbon removal, provided that a right-of-way shall not be granted if inconsistent with the purposes of the reservation (30 U.S.C. §185(b)). Also, the ANWR is now within the National Wildlife Refuge System (16 U.S.C. 668dd) which permits easements for pipelines when the Secretary determines compatible use, 16 U.S.C. 668dd(d)(1)(B).

The Conservation Intervenors 15/ and the State of Alaska both opposed Arctic's crossing of the ANWR. They questioned the technical feasibility of the snow roads and snow work pads that Arctic proposes to use to avoid damage to the fragile tundra and permafrost regime and to avoid

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14/ This area is roughly 2.4 percent of the total area of Alaska and is about one-quarter the size of either Illinois or Georgia.

15/ Sierra Club, The Wilderness Society, National Audubon Society, and the Alaska Conservation Society.

interference with caribou breeding and birdlife. Even should these techniques prove feasible, the intervenors have another concern. Arctic plans to construct the Alaskan portion of its system in the winter of the last year before operations are schedule to begin. The intervenors fear that if the proposed snow road plan should encounter problems, there will be strong economic pressure (with two and one-half years of construction already completed) to abandon the snow road technique and resort to gravel roads and work pads, or whatever else is necessary, to complete construction.

There is further concern that any intrusion by man, even a buried pipeline, is inconsistent with the "wilderness" value of the Range. Alaska's Governor Hammond has said:

> "We believe that we should not squander the rare and precious resource of untouched northern wilderness. Some day perhaps, we will need to have the oil and gas resources of the Range, if any, even more than we need to have the resource of wilderness, but clearly we should not allow construction of a gas pipeline in the Arctic National Wildlife Range when other less damaging alternatives are available, as they are." 16/

Another concern is that even if the mitigative measures are adequate, once the Range has been penetrated, its subsequent development is a certainty.

We believe, however, that Arctic's proposed snow road construction can be made technically and environmentally feasible and that sufficient water exists to make snow without undue environmental impact. (See Chapters V and VIII.) We believe also that Arctic has demonstrated that its crossing of the Arctic National Wildlife Range will not have an adverse environmental impact if the proposed mitigative measures are taken. However, we are aware that the decision

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16/ ALA-1.

to allow the Range to be crossed rests with the Secretary of the Interior. 17/

We also note that Arctic would have two years of snow road experience before beginning the wildlife range phase of construction. However, should Arctic encounter schedule difficulties, we would strongly oppose any deviation from the original proposal and would urge the Secretary of the Interior to disapprove any such deviation. If construction could not be completed within the original deadline, then completion of the project would simply have to be delayed. 18/

Finally, we believe it is possible to approve a buried pipeline through the Range without setting in motion an inevitable progressive violation of the Range. Alaska and the Department of the Interior have full authority to limit any further activity.

In summary, Arctic's proposed crossing of the Arctic National Wildlife Range is deemed to be environmentally acceptable given the proposed terms and conditions. 19/

2. The Mackenzie Delta

Arctic's crossing of the Mackenzie Delta, including a 4.5 mile crossing of Shallow Bay near the mouth of the Mackenzie River, is projected to have some impact on snow geese and beluga whales.

Snow geese breed in the Arctic and use the North Slope and Delta areas for staging prior to their winter migration

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17/ If Congress should authorize Arctic Gas, Section 9, of the Alaska Natural Gas Transportation Act would seem to require issuance of the necessary right-of-way or permit.

18/ It must be noted that by that time the Canadian portion of the line will be operational. Thus, the investment would not be entirely idle.

19/ See Chapter XIII.

southward. If early snow drives them from the North Slope (which occurs about one year in eight), 275,000 geese may be in the area from late August to late September. These birds are skittish and noise from a compressor station will likely keep them from lighting and feeding in the adjacent area. Aircraft flights could disrupt feeding and resting activities crucial to strength-building prior to migration.

Arctic's intention to relocate compressor station CD-08 from the central part of the outer Delta eastward to Tununuk Junction solves the first problem. Weather and ice conditions dictate summer construction across Shallow Bay, but construction could be interrupted for approximately two weeks if a large build-up of geese materializes. Furthermore, projected aircraft flights of 4-5 per week at a minimum altitude of 2,000 feet are well below a level of disruption that would weaken the flock. Presumably, the Canadian Government will require appropriate measures if the Arctic proposal is chosen.

The beluga (white) whales migrate to the Mackenzie estuary each summer, presumably for calving. While some whale activity has been observed landward of the proposed pipeline crossing of Shallow Bay, there is no indication that construction activity will have a detrimental effect on their routine.

3. The Chugach National Forest

The El Paso proposal also has unique environmental impacts. First, it passes through the Chugach National Forest, an area of spectacular beauty which supports numerous forms of wildlife. Having examined both the Arctic National Wildlife Range and the Chugach National Forest first-hand, we agree with Judge Litt that Chugach is as much a wilderness area as the Wildlife Range and deserves as much consideration. However, the flora, fauna and soils of the Chugach are not nearly as fragile, or slow to heal after construction impact as those of the North Slope. A gravel haul road and LNG plant will undeniably mar some of the landscape of the Chugach, but we consider these impacts tolerable.

4. Prince William Sound

The effect of the heat discharge from El Paso's LNG plant on aquatic life in Prince William Sound was also considered. El Paso has not presented any baseline oceanographic studies of population and temperature tolerance necessary to determine if their proposed water cooling system is environmentally acceptable. Consequently, Judge Litt found that the El Paso design must include cooling towers unless El Paso can present evidence of acceptable environmental impact. Judge Litt, however, did not consider the environmental problems of cooling towers themselves. These towers are of two types, both of which present environmental problems. Dry cooling towers are large, unattractive, and make a great noise. Wet cooling towers create fog and icing. Both systems are costly and consume a substantial amount of energy in operating the pumps and other equipment. Thus, an acceptable solution to the heat discharge problem for the El Paso proposal has not been proposed.

Some concern has also been expressed regarding the likelihood of subsequent industrialization, particularly petrochemical, in the Sound area if the El Paso facility is constructed and the state chooses to sell its royalty gas in Alaska. That decision is a significant separate issue, to be addressed if and when the state decides to do so. As we indicate in our socioeconomic assessment (Chapter VI), limited Alaskan markets and large transportation costs are likely to discourage the development of a petrochemical industry in Alaska. Furthermore, actions can be undertaken to limit petrochemical plant discharges to an environmentally acceptable level. We would expect EPA and the State of Alaska to see that those actions would be taken.

5. Utility Corridor Concept

El Paso and Alcan base much of their claimed environmental superiority over Arctic on their use of an existing utility corridor. Both follow the Alyeska pipeline corridor and, although Alcan veers away from the oil pipeline southeast of Fairbanks, it then follows the Alaska Highway and Haines Products pipeline right-of-way. Although the construction and operation impacts would be smaller than for a wholly new route, we find that the overall difference is not substantial. 20/ El Paso will require a new right-of-way within the utility corridor since it runs parallel, but not adjacent to, the Alyeska line. Alcan's proposed alignment is adjacent to the line but it appears that an entirely new workpad will be required with its attendant gravel requirements. 21/ Also, alignment "adjacent to" the oil pipeline actually involves crossing it a number of times; for example, El Paso's alternate alignment adjacent to the oil pipeline would cross the Alyeska fuel gas line seven times and the oil pipeline 35 times. Also, thicker-walled pipe would likely be required if the gas pipeline runs next to the haul road, costing another $200 million in the case of El Paso. Thus, close alignment to an existing corridor may reduce some environmental impact, but it will

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20/ This is not to say that these routes do not benefit substantially from the existence of an all-weather road for both construction and maintenance.

21/ The Alyeska line is underground where the soil is thaw-stable. There blasting will likely be required to complete the gas pipeline trench and at least 200 feet separation between the pipelines probably will be required to neutralize blasting shock. Where the Alyeska line is above ground, gas pipeline construction activity must avoid striking either the oil pipe or its vertical support members; this also requires at least an extensive widening of the workpad if not a completely new one. See Chapter VIII.

also create oil pipeline integrity problems and may require additional costs. 22/

For these reasons, we fail to find alignment in an existing utility corridor to be a compelling reason to choose one transportation system over another. Each system must be judged on its own total impact and that impact cannot be assumed negligible simply because the system is constructed in an existing utility corridor.

6. Environmental Significance of Maple Leaf and the Richard Island Lateral

If either El Paso or Alcan is chosen, a separate pipeline leg would be required to transport Mackenzie Delta gas to market, if and when Canada decides to develop these reserves. Two specific alternatives have been proposed: (1) the Maple Leaf Project, which would follow a route similar to Arctic's, along the Mackenzie River, and (2) the Richards Island Lateral (Dempster Highway Route), which would follow a route westward south of the Mackenzie River to join the Alcan system near Whitehorse, Yukon. See Exhibit V-3D.

However, in evaluating comparative environmental impacts, we do not believe it is appropriate to compare "El Paso plus Maple Leaf" or "Alcan plus Richards Island Lateral." These additional lines are exclusively Canadian. Canadian authorities have exclusive jurisdiction over timing of development and the method by which Mackenzie Delta reserves will be brought to market. There is no point to our hypothesizing about those decisions.

22/ El Paso originally proposed an alignment close to the Alyeska pipeline (within 3,000 feet for 85 percent the distance). The State of Alaska urged realignment to bring the gas pipeline immediately adjacent to the oil pipeline. El Paso somewhat reluctantly filed a realignment case which it never supported. Neither did Judge Litt, nor do we.

7. The Most Gas

Claims of environmental superiority for each system must be considered to some extent against the gas deliveries projected for each.

Arctic has claimed its net environmental impact is positive since clean-burning natural gas will produce less environmental pollution than other fuels. The same can be said for all three systems. However, Arctic is in fact the most economical of the three systems in terms of efficiency in delivering fuel.

System	Annual Input At Design Flow (Trillion Btu's)	Annual Btu Deliveries	Fuel Efficiency (%) 23/
Arctic	942.8	885.7	93.9
Alcan	996.9	933.5	93.6
El Paso	974.0	867.8	89.1

Thus, Arctic can deliver a higher percentage of Prudhoe Bay's gas to the United States markets than the other systems; Alcan runs a close second.

8. Conclusion

We believe we have complied with the National Environmental Protection Act (NEPA) in exploring alternatives. Each system has changed substantially from its original routing and design in response to criticisms raised and alternatives explored during the two years of these proceedings. The Alcan proposal, itself, started as an alternative without a sponsor. The perfecting techniques required by NEPA, which have caused in this proceeding substantial changes and improvements, prove the desirability and effectiveness of the NEPA requirements.

23/ These data are incorporated into the net national economic benefit calculations in Chapter IV.

As a result of these modifications and others which will continue to be made, we find that each of the three systems is environmentally acceptable. No doubt, the Alcan route promises the least environmental impact, if proper mitigative actions are taken during final design, construction, and operation. We do not find Arctic's crossing of the Arctic National Wildlife Range to be disqualifying, nor do we find El Paso's crossing of the Chugach National Forest unacceptable, given the environmental protections proposed in each case.

A buried pipeline is probably the most environmentally acceptable transportation method. It leaves insignificant traces when compared to the environmental disruption inevitable from other methods of transportation.

J. Socio-Economic Impacts

Alaska will be the principal beneficiary of gas pipeline construction. The socio-economic impacts will be greater than on any other state, and the benefits will be largely independent of the system chosen.

The benefits will flow from royalties and severance taxes and, to a lesser extent, property taxes from the operation of the pipeline itself. These government revenues will amount to between $1 and $2 billion between 1981 and 1990. Personal and corporate income taxes will add several hundred million dollars more. Offsetting those benefits will be increased expenditures for the entire range of government activities, though such expenditures will stimulate economic activity in the State. If history is any guide, this will lead to increases in population, employment, and the general economic well-being of Alaska.

During construction, however, the State should again be prepared for the substantial social and economic dislocations which accompany major projects, especially those associated with population increases resulting from an influx of job-seekers.

In the "lower 48", the impact will be much milder, but also beneficial, due to increased tax revenues to state and local jurisdictions along the pipeline route.

Canadian impacts will be mild overall, but especially significant for the isolated native communities, which have maintained their traditional life and subsistence economy.

We conclude that the relative socio-economic impact of each would be as follows:

1. El Paso would generate more jobs, more personal income, more property subject to tax, and more indirect economic activity than would the other proposals, but it would also require more social services and would probably be associated with the highest unemployment.

2. These impacts would be much smaller for Arctic Gas and somewhere in between for Alcan.

3. There is a possibility that Arctic Gas, with its lower projected transportation cost, would produce higher royalty income for Alaska, which would aid the State in financing industrial development and expanding its social services.

K. Geotechnical Problems and Reliability

1. Seismic Activity

The principal geotechnical problem facing El Paso is exposure to seismic risks. El Paso's proposed cryogenic delivery system is highly interdependent. Failure of any part of the system could quickly halt delivery of Prudhoe Bay gas, and a major disaster could stop delivery for several months to a year or more. Seismic problems are particularly bothersome since containers in a cryogenic state are more brittle.

El Paso's facilities are subject to the intense seismic activities of south-central Alaska. The proposed pipeline crosses three major active faults (the Donnelly Dome at MP542, the Denali Fault at MP573, and the McGinnis Bay Fault at MP582). 24/ Also, the Point Gravina site for the LNG liquefaction facilities could encounter substantial seismic activity. The epicenter of the 1964 Alaska earthquake was only 50 miles from Point Gravina. That quake caused a 4-foot uplift and 30-foot horizontal movement at the site. While El Paso's system supposedly is designed to withstand an earthquake of 8.5 Richter scale 25/ intensity and 0.6g ground acceleration, the design is described only in general terms. 26/ For example, estimated costs are based upon the existence of bedrock at the liquefaction site, though no core samples have

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24/ MP = mile post.

25/ The Richter scale is logarithmic. Thus, an event of magnitude 8.0 is 10 times as intense as one of 7.0 magnitude.

26/ Arctic contends that El Paso's seismic design spectra and allowable stress levels have not been sufficiently described to permit judgment to be applied.

been taken. 27/ The absence of bedrock would increase costs to provide system integrity.

Potential seismic activities also pose the dual problems of tsunamis (gravitational sea waves produced by any large scale, short duration disturbances of the ocean floor - principally by a shallow submarine earthquake) and seiches (free or standing-wave oscillations of the surface water in an enclosed or semi-enclosed basin) for El Paso. El Paso contends the facilities are designed to withstand these phenomena. Given the location of Gravina Point and its surrounding geography and geology, the magnitude of risk is far from clear, causing Judge Litt to suggest that "it would be advisable and prudent for El Paso to redesign the marine terminal when the berths are occupied for a 20-foot design wave." 28/ Here again, El Paso will have to provide additional information before a design can be approved.

Alcan crosses no known active faults in Alaska. The Denali Fault is approximately 30 miles away at its closest point. In Canada, Alcan traverses the Shakwab Fault, which is large, but not likely to be active.

The Arctic route traverses a zone of high seismic near the Mackenzie Delta. Little is known about specific fault locations or activities but the maximum expected magnitude is 7.0 (Richter) in that general area. 29/

27/ I.D. 103, n. 2; Staff Brief on Exceptions, 36; Alcan's Brief on Exceptions, 138.

28/ I.D. 107.

29/ In a somewhat related issue, Arctic proposes twin 36-inch pipelines for 36.5 miles in the Shallow Bay area of the Mackenzie Delta. This dual design is not for seismic protection, but for repair accessibility during spring ice break-up and high water season.

2. Frost Heave and Metallurgy

In permafrost regions (see Exhibit V-1), the gas in the pipeline must be chilled below 32° F. to avoid melting the permafrost and creating settlement problems. Where permafrost is absent, water coming into contact with the pipe will freeze, expand, and press on the pipe. This stress could actually crack the pipe or force it out of the ground. The frost heave problem faces all three applicants.

Arctic, which has the most mileage in the discontinuous permafrost zone, has proposed a heating system to keep water away from the pipe in the areas where frost heave might occur. Alcan believes special ditching and filling will be an adequate solution. El Paso has not determined a preferred design. Whichever system is chosen, more experimentation needs to be done to determine the best means of combating frost heave. We have no doubt that an adequate solution can be found and will be available to whichever applicant is chosen.

These conclusions also hold for the problem of pipeline metallurgy. A pipeline is more susceptible to fracture when chilled. 30/ Arctic has proposed the use of crack arrestors while Alcan has suggested they are not needed. The Department of Transportation believes that the question of the arrestor's interference with cathodic protection must be resolved. 31/

3. LNG Safety and Siting

We do not believe that an LNG system is inherently less reliable or more dangerous than a high pressure buried

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30/ While Arctic and El Paso both propose to operate at 1680 psi, and Alcan at 1260 psi, all three would be subject to about the same stress factors and are generally subject to the fracturing problem.

31/ A method of protecting a pipeline from external corrosion by preventing ion migration from the pipe through use of a sacrificial anode.

pipeline. Nevertheless, liquefaction and regasification facilities must be planned with the utmost care.

Gravina Point is El Paso's preferred site for the LNG facility in Alaska. While Gravina Point is acceptable, we believe further exploration of the Cape Starichkof site proposed by Staff is needed before a final choice is made. This site offers the possible benefits of lower seismic risk, lower pipeline construction costs, and avoidance of the Chugach National Forest. On the other hand, the Cape Starichkof site would result in a longer voyage for the tankers, possibly requiring larger ships or an additional vessel. 32/ Ice problems in Cook Inlet may reduce reliability, and the pipeline route to the site may have environmental impacts that have not been fully evaluated. The State of Alaska succinctly summarized the issue in the initial brief on the subject: "There is insufficient evidence to reject Gravina Point -- or to prefer Cape Starichkof -- on environmental, socio-economic, or any other grounds."

The regasification facilities in California raise similar siting issues. El Paso proposes to use Point Conception, an area of limited development. Staff would place the terminal at Oxnard, in a developing industrial area. The question involves not only the siting of facilities for El Paso, but also two other proposed LNG projects. 33/ Western LNG, which would own and operate all three facilities, has proposed three separate sites -- Oxnard, Point Conception, and Los Angeles -- in order to minimize the possibility of losing all three supplies simultaneously due to earthquake damage or other catastrophe.

32/ See Chapter VIII.

33/ The other two projects are Pacific Indonesia and Pacific Alaska, with ships from the latter coming from an LNG plant in Cook Inlet. The gas supply for this plant is southern Alaska reserves. With the exception of two cargoes sent this winter through the Panama Canal to the gas-deficient eastern states, gas from the Cook Inlet currently goes to Japan since no regasification facilities are located on the West Coast.

While Judge Litt and Staff believe one site, with its economies of scale and lower total environmental impact, is preferred, we need not decide that issue now. Rather than assign sites for all three projects at this time, we believe the environmentally preferred site should be assigned to the first project certificated. The others may never materialize. On that basis, we believe that the Oxnard site should be certificate first, despite increased costs 34/ due to the need for larger tankers or an additional tanker to compensate for the additional mileage.

Of course, the State of California will have to consent to this siting and a GAO report on LNG safety scheduled for completion this summer may provide additional information.

4. Conclusion

We find that all three proposals are sufficiently reliable to warrant certification. El Paso is clearly most susceptible to some form of temporary interruption, but the flexibility of its modular design would limit most impacts to reduced delivery rather than total system failure. El Paso is also most susceptible to an extended outage if there should be a major earthquake at either its liquefaction or regasification plants, although we believe the system can be designed to limit this possibility to an acceptable level.

Frost heave and metallurgy problems are common to all systems. We believe adequate measures can be taken to assure a high degree of reliability, and that in the case of frost heave, no applicant has proven yet that its remedy is preferable. Additional study will be required.

34/ These cost increases will be partially offset by shorter pipeline requirement and less expensive utility connections at the Oxnard site.

L. Construction Costs and Scheduling

Capital cost estimates for the projects as stated by the respective applicants are within a close range. In millions of 1975 dollars the capital cost estimates are:

	With AFUDC	Without AFUDC	System Capacity
Arctic Gas	$ 6,728.5	$ 5,620.5	2.25 Bcfd
El Paso	6,570.8	5,587.5	2.361 Bcfd
Alcan	6,761.2	5,780.9	2.4 Bcfd

Obviously, with construction continuing through 1983, inflation will significantly increase the actual dollar expenditures for any of the systems, even with no "cost overrun." However, the 1975 dollar costs provide a reasonable basis for comparison of the systems and their relative costs of service.

We do not believe that any of the systems are free from risks of cost overruns and delays in completion: each applicant will be operating at the margin of current technology; construction conditions are frequently harsh; final plans for design and construction are not yet developed.

Nevertheless, we believe that each system's risk of cost overrun and delay in completion is acceptable, and there is virtually no chance that any system would become so costly as to be uneconomic.

We first consider the reliability of the direct capital cost estimates. 35/ We believe El Paso has underestimated the direct capital costs of the Prudhoe Bay to California segment of its system by seven to ten percent. We believe that Alcan has underestimated the expected direct costs of

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35/ Excluding AFUDC.

its Alaska segment by approximately five percent and at least ten percent on the section in Canada. We find that the Arctic system has estimated its construction costs reasonably accurately. While all three systems face some winter-induced cost overruns, Arctic has the highest exposure and there is a high probability that the construction costs in the northernmost areas of that system will increase between seven and ten percent, resulting in an overall system cost increase of less than five percent. The likelihood of comparable weather-induced cost overruns is less for El Paso and almost nil for Alcan.

Next we consider time delay which results in cost increases from AFUDC. We find that El Paso has a high probability of completing construction on schedule. We find that Alcan has a high probability of at least a nine-month delay in commencement of deliveries attributable to delay both in beginning construction and in completion time. We find that Arctic has some probability of up to a one-year delay in the commencement of deliveries from Prudhoe Bay. 36/

This uncertainty arises principally from weather. Since Arctic is depending on winter construction, snow roads and snow workpads, an unually short winter or unusually severe weather could delay completion.

Even with these probabilities of delay, Alcan will be able to commence deliveries six months prior to El Paso and nine months to one year prior to Arctic because of its considerably shorter construction schedule. 37/

36/ Both El Paso and Alcan start deliveries at less than design capacity.

37/ Our cost of service studies have indicated that in the unlikely event that both cost overruns of $270 million were incurred and a one-year delay was experienced, the 20-year average cost of service would increase by only 9¢ per MMBtu.

Arctic Gas

Arctic plans to commence pipeline construction in the winter of year 4, October 1980, with nine spreads (denoted as spreads A through I) operating between Tununuk in the Mackenzie Delta area of the Northwest Territories and a point north of Caroline Junction in Alberta Province. Above the 65th parallel, crews will operate on roads and workpads constructed of compacted snow. Construction will continue until the spring thaw the following April or May. Each of the nine spreads is expected to lay approximately 75 to 80 miles of pipe. The next two summers, spreads H and I will lay pipe in southern Alberta and Saskatchewan. In the winter of year 5, 1981-1982, spreads A through I essentially will continue the plan of the previous winter. By spring of 1982, the pipeline will be completed from Richards Island to Caroline Junction and delivery of Canadian gas from the Mackenzie Delta is scheduled to commence in the summer of 1982.

In October of 1982, spreads A through F will commence construction on the North Slope between Prudhoe Bay and Tununuk Junction, 195 miles in Alaska and 177 miles in Canada. Construction across the North Slope will be exclusively on snow roads and snow workpads.

The most contested features of the Arctic plan are the winter construction and the snow roads and workpads, particularly in the North Slope region.

All things considered, welders, operators and laborers probably would prefer Philadelphia to winter construction in the Arctic. Consequently, the Arctic plan has inspired unrelenting prophecies of doom, accompanied by descriptions of darkness, high winds and cold or no cold, snow or no snow. 38/

38/ *E.g.*, Alcan Brief on Exceptions, p. 116; El Paso Brief on Exceptions, p. 20.

Even El Paso, which itself proposes winter construction for most of its route in Alaska, joins the critical chorus by questioning whether "men and equipment will operate in the dead of the Arctic winter." 39/ Nevertheless, substantial evidence in the record supports the feasibility of winter construction, if reasonable protective measures are applied. Machines can be prepared and men equipped to enable construction to proceed in all except the most severe conditions. Hundreds of miles of major pipeline have been constructed in the winter. Well drilling at Prudhoe Bay is conducted in the winter. The extensive oil gathering system at Prudhoe Bay was constructed in two winters with minimal weather-induced down time. Of course, none of these projects is directly comparable to the Arctic project in terms of magnitude or overall complexity but they do prove that men and machines can work in the high Arctic winter. There is no reason why the experiences cannot, with the proper planning, be "scaled-up."

It is also argued that snowfall in the region is insufficient to build the needed roads and workpad. Arctic answers that it can harvest snow from lakes adjacent to the right of way and, to the extent necessary, manufacture artificial snow. It is further argued that there is not sufficient water to make snow. The evidence supports a conclusion that sufficient water is available in early winter from lakes and streams. Several year-around springs are also available for water supply, although great care must be taken in drawing water from springs to avoid harm to aquatic life. We find that Arctic has stated realistic water demands and has identified adequate water for the contingency of abnormally low snowfall.

39/ El Paso Brief on Exceptions, p. 13.

It is also argued that snow roads lack sufficient strength or durability. Arctic has conducted an extensive test at Inuvik in the Northwest Territories. Alyeska's experience with snow pads in the construction of its gas fuel line was also satisfactory. 40/ Those tests demonstrate to our satisfaction that snow roads and snow work pads are feasible. When properly prepared and maintained, they can provide a stable work surface and yet protect the tundra and permafrost environment.

Arctic has relied upon experienced contractors to design the facilities and plan for winter construction; we find the results to be credible. There is no dispute that winter construction poses greater economic risks than summer construction, but it also is clear that in Arctic regions winter construction is environmentally sounder. We find Arctic's basic plan to be reasonable.

Another construction issue is the productivity, or rate of pipe laying. Arctic proposes a rate for the North Slope of 0.71 miles per working day per spread or 0.50 miles per calendar day. 41/ Each spread would be staffed to produce 1.0 miles per working day and 0.71 is reasonably attainable. This rate was realized on average by Alyeska in 1976. Granted, Alyeska construction occurred in summer, but the pipe was laid through mountainous terrain and the project involved frequent switches between elevated and buried construction which diminished productivity.

If productivity should slip below 0.71 miles per day, Arctic has a reasonable margin in its construction season to pick up the slack. Finally, for the critical North Slope construction in the final year, additional spreads could be

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40/ T. 32,592-32,596.

41/ The difference in calendar and working days reflects down time for bad weather, vacations, etc.

mobilized at a cost of about $120 million, in which case productivity of only slightly more than one-third of a mile per calendar day would fulfill the production schedule.

The Arctic estimate of productivity for the Alberta section of its line is conservative when compared with the estimates submitted by Alcan for virtually the same terrain.

We find the Arctic construction program to be well-planned and attainable. The project runs slight risks that extraordinarily warm or cold weather could delay entry upon the tundra, prevent winter work for an extended period, or force premature cessation of construction in the spring. But we believe the risk of a disabling combination of events to be small.

Further, should construction not be completed on schedule, we do not believe that the consequence would be an entire year's delay. Under the most extreme weather conditions conceivable, some construction would be accomplished in that first year on the North Slope. The amount of remaining work should not require an entire season in the following year. Thus, a delay of 8-9 months is more likely than one year.

El Paso

El Paso would build the Alaska pipeline from Prudhoe Bay to Gravina Point commencing late in the third year of its overall schedule and concluding late in the fifth year. Winter construction on snow work pads would be the dominant method. Summer construction would take place in the Chugach Mountains and other areas where wind and snow conditions are too severe to permit winter construction. Six spreads will be employed, and expected productivities will range from .67 miles per working day in the relatively flat areas near Fairbanks to .26 miles in the Chugach Mountains.

El Paso's winter pipeline construction plan is not seriously contested. It will have the benefit of the Alyeska haul road and Richardson Highway and will use snow only for work pads.

Construction on the Gravina Point liquefaction plant will commence late in the second year, and the plant should be operational by late 1982. Fabrication of the LNG tanker fleet will commence in the second year and three ships are scheduled for completion late in the fifth year, three in the middle of the sixth year, and the final two in November of the sixth year.

The California regasification facilities and the pipeline of Western LNG will be operational by the end of the fifth year, as will the El Paso Natural facilities to transport gas across Texas. El Paso plans to deliver some volumes in 1983 during the testing and start-up period. Full operation will commence in 1984.

The principal challenge to the El Paso construction schedule relates to the necessary pre-construction seismic design for the pipeline in southern Alaska and the Gravina Point facilities. To date, El Paso has completed only superficial geologic analyses of the areas and only general design parameters have been stated for the facilities. Clearly, much work must be done before actual construction can commence. However, we find that sufficient lead time has been allowed in the schedule to accommodate this need. It is, however, likely that some unbudgeted additional costs will be necessary to insure timely development of the data and plans.

We find the overall El Paso cost estimate reasonably accurate. However, a high probability exists that unplanned additional expenditures will be required to expedite geotechnical research, meet seismic design requirements, deal with the thermal discharge problem at Gravina Point, and to resolve some other relatively minor matters. Overall, we believe that these demands could add seven to ten percent to the cost estimates presented by El Paso.

Judge Litt found that El Paso would require an additional LNG train at Gravina Point and an additional ship. We disagree as to the LNG train. However, we believe that either an additional ship or increasing the capacity of the eight proposed ships will be required to transport the required amount of LNG to California. Another ship would increase the El Paso capital costs by approximately $200 million. No estimates have been made of the cost of ship expansion.

Alcan

Alcan proposes to commence pipeline construction throughout its entire system in April of 1980 and complete it by the end of summer of the following year. All construction in Alaska is projected from April to the end of September. In Canada, some winter construction is planned. During the two construction seasons, Alcan proposes to construct a total of 4,782 miles of pipeline in the United States and Canada.

Alcan has yet to settle upon a final alignment with Alyeska, to complete many detailed environmental and geotechnical studies, or to complete many essential tasks before actual commencement of pipeline construction. We, therefore, believe it unlikely that Alcan can commence construction, particularly in Alaska, prior to mid-1980.

Overall productivity estimates employed by Alcan also bear further scrutiny. Alcan projects .71 miles per day in Alaska, the same as projected by Arctic for the North Slope. This appears reasonable given that Alcan proposes summer rather than winter construction, but must traverse much more rugged terrain than Arctic. In Canada, however, the productivity estimates increase to a peak in Alberta of 1.42 miles per day for summer and 1.14 miles per day for winter. The winter figure is about 40 percent higher than the Arctic estimates for essentially the same type of terrain. Both cannot be correct.

At the peak, 24 mainline construction spreads and 18 compressor station crews will be required to complete construction on schedule, a total of more than 17,358 personnel. We believe that this extraordinary labor demand, in light of the labor supply currently available in Canada, will have an adverse effect on the overall productivity of the project, with resulting delays.

Consequently, we conclude a high probability exists that Alcan would not complete its project until the summer of 1982.

Judge Litt found that the Alcan summer construction plan for Alaska was environmentally unacceptable. We modify that finding and conclude that in general the plan is acceptable. However, we recommend that Alcan schedule construction in ice-rich permafrost areas when the temperature is below freezing to prevent unnecessary damage to the vegetative mat and permafrost regime. These areas would have to be identified by the Federal inspector.

The Alcan cost estimates for the 48" alternative proposal have not been subjected to detailed inquiry by the other applicants or Staff due to their late filing. 42/ On the basis of the limited evidence before us, we conclude that Alcan's cost estimates appear to be reasonable in Alaska, although an undetermined cost increase could result from a re-examination and modification of the alignment along the Alyeska right-of-way. The modification could result from a necessity to locate the pipeline further from the Alyeska oil line than planned.

There are also unanswered questions concerning the cost estimates for the Canadian sections. Overall costs in Canada are estimated at approximately one-half of the Alaska costs, and much lower than the costs estimated by Arctic for construction in Canada. Despite these uncertainties, we have no reason to believe that the Alcan system could not be constructed with only moderate cost overrun from their filed cost estimates.

42/ While it would be unfair to hold the lateness of Alcan's filing against their application, we realize that Arctic and El Paso have been in the bowl much longer and hold few, if any, secrets from the eyes of the other parties.

M. Competitive Impact Assessment

It is our conclusion that the certification of a particular Alaskan gas transportation system will not have any significant impact on pipeline competition within the United States. Though the choice of a particular transportation system will affect the cost of Alaskan gas between regions, that choice will not have any significant impact on interpipeline competition between regions because such competition generally occurs within a region.

The competitive impact of the Alaskan gas transportation system will be determined by a complex interaction of economic, regulatory and engineering factors. The two most important factors will be the extensive use of displacement procedures and the imposition of a broad distribution of gas. Transporting Alaskan gas through the lower 48 states by displacement will entail a greater degree of coordination among U. S. pipelines than has existed to date. Such coordination will lessen competition and may even produce restrictive agreements which may be necessary and subsidiary to implementing the displacement procedures, but in other contexts would be unreasonable.

Under a broad distribution plan, the amount of Alaskan gas received by any individual pipeline will be limited. Therefore, whatever impact the Alaskan gas has on overall supply costs will be approximately the same for all pipelines. Consequently, the Alaskan gas will have a neutral effect on competition between pipelines in regional markets. A broad distribution of gas will not have a neutral impact in the gas supply market. Any imposed distribution plan is an interference with the market. Nevertheless, the overall effect of a broad distribution may be competitive if it reduces the likelihood of restrictive agreements in other energy markets.

N. Financing and Tariffs

1. Introduction

The Alaska Natural Gas Transportation Act of 1976 requires the Commission to evaluate the feasibility of financing the proposed projects. Each of the projects would be constructed in part under Arctic winter conditions. Each could ultimately cost over $10 billion. Each would present a financing challenge greater than any previously considered by this Commission. (Hereafter, we use "the project" to mean the system ultimately chosen.) The hearing record makes clear that the gas utility sponsors currently proposed do not have the financial strength to finance the project to completion.

Judge Litt concluded that in the absence of additional creditworthy parties, ". . . the project financing required here will require either consumer or government backstopping, or both, to guarantee project completion." We agree fully with this conclusion. However, we believe additional creditworthy parties could be induced to back the project.

In particular, the State of Alaska indicated at the oral argument that it ". . . is searching for a way to participate meaningfully in the financing of the El Paso project . . .", and that if the El Paso project is ruled out ". . . the State would then seriously consider whether to assist the financing of the Alcan Project." Further, the Atlantic Richfield Company - a major Alaskan gas producer - indicates an open mind regarding project investment. The Department of the Treasury continues to suggest the possibility of participation by industrial gas consumers. We would also prefer to see more gas pipeline and distribution companies involved in the purchase of Alaskan gas and in the transportation system financing.

If sucessful, a traditional financing approach involving these parties would minimize consumer investment guarantees and avoid involving general taxpayers. To the extent possible, we believe end-use gas customers should retain their traditional role of paying for energy as it is consumed, rather than bearing the risks of a new enterprise.

Our finance and tariff recommendations initially focus on several proposals which we hope will provide adequate incentives to private parties and the State of Alaska to invest the necessary capital, while bearing acceptable risks. Since some of our proposals were not fully considered in the record, a special proceeding to perfect the details may be needed in the near future.

We have also considered an alternative financing approach which shifts more risk to consumers by having them guarantee repayment of the project's debt financing. If such consumer guarantees are required, consumers' financial interest must be protected and they must receive appropriate compensation.

We have not recommended federal financial assistance. However, if such taxpayer guarantees are to be avoided, we believe that innovative approaches are required in this unique project financing situation.

2. Financial and Economic Risks

Any of the projects have certain risks, including an uneconomic delivered cost of gas, extended service interruption, and project noncompletion. While we view each of these contingencies as being very unlikely, in total the risks associated with building and operating a project of this magnitude are greater than in any gas utility project which this Commission has ever certificated. Recognizing this higher level of risk, we will consider herein gas pricing and rate of return arrangements which we believe would offer private parties an incentive both to supply the necessary capital and to bear the risks associated with the project. Special care has been taken to provide incentives for efficiency in construction and operation of the project.

The credit backing for the debt financing will be crucial to providing adequate amounts of financing. Institutional lenders require guarantees which provide good prospects for recovering their loans with interest even if the project fails completely.

3. <u>The Pricing of Alaskan Gas</u>

The New York State Public Service Commission proposed incremental pricing of Alaskan gas. The consensus of financial experts was that the project could not be financed on that basis, because of doubt as to the marketability of the gas. We have shown elsewhere that all the proposed projects have large expected net national economic benefits and we are convinced that the projected cost of transportation is low enough to insure marketability. Rolled-in pricing will assist in obtaining the critical financing to deliver an important part of our national energy supplies. Since we believe that a market test is not essential, we recommend that rolled-in pricing (averaging the price of this gas with all other gas in the purchaser's system) be adopted.

4. <u>Field Price for Gas</u>

We believe it is imperative that the price of Prudhoe Bay Alaskan gas be established as quickly as possible. We, therefore, propose to establish in the near future a proceeding to determine an appropriate field price for Prudhoe Bay gas.

First, the gas producers have indicated that the prior establishment of a sale price is a precondition to entering into gas sales contracts.

A second issue relating to the field price for Alaskan gas is whether by deregulation, or by setting a relatively high maximum price, it might be possible to attract gas producer participation in the transportation system financing either directly or through debt guarantees.

We are prepared, however, to examine pricing mechanisms other than setting a fixed price. One possible method for pricing Alaskan gas would be to set the price by the following formula:

Field Price = Market Value - Transportation Cost.

A minimum field price could also be allowed, to insure that producers recover their incremental costs for producing and conditioning gas.

The "market value" for Alaskan gas would most likely be set by reference to the city-gate cost of incremental gas or energy supplies. As for the transportation cost used in the formula, the national average cost to selected major market areas would seem most appropriate.

Besides removing the possibility that producers could exercise monopoly power in the pricing of Alaskan gas, formula pricing would have other advantages over a fixed maximum field price.

First, it avoids the difficult problem of allocating joint costs of gas produced in association with oil, which is the situation in Prudhoe Bay.

Second, a pricing formula offers consumers significant protection against paying a price higher than market value for Alaskan gas, even with a cost of service tariff and rolled-in pricing. Under the formula, transportation cost increases are offset by corresponding reductions in the field price.

For these and other reasons, we believe that a formula approach to determining the field price for Alaskan gas has considerable merit. However, under the Natural Gas Act, the authority of the Commission to approve such a pricing procedure could be challenged. Thus, we urge the President to submit legislation to authorize the Commission to determine field or wellhead rates for Prudhoe Bay gas on the basis of market factors and alternative fuel prices.

5. Gas Distribution

The economic and financing implications of Alaskan gas distribution among gas pipeline and distribution company shippers should not be ignored. The equity investments of the currently proposed gas utility sponsors are large relative to their financing capabilities. There is a chance of a significant increase in the price of other flowing gas if consumers are required to make guaranteed debt service payments. These factors argue against a concentration of Alaskan gas ownership.

Likewise, there could be significant economic disruption should Alaskan gas be concentrated in particular markets and an extended service interruption occur. In addition, some possibility exists that Alaskan gas might be more expensive than alternative gas or energy supplies by the time it is brought to market; a concentration of Alaskan gas in certain areas could place one area of the country or set of gas consumers at a disadvantage. Therefore, on both economic and financial grounds, we favor a reasonably broad distribution of Alaskan gas across domestic markets.

6. Project Sponsor Debt Guarantee Financing Approach

Under this approach there are three basic objectives. First, to achieve a successful private financing by providing incentives for the maximum amount of risk bearing by the project's potential sponsors. Second, to minimize the likelihood that consumers will have to pay higher than market value for Alaskan gas, or incur substantial expenses in the case of project noncompletion or extended service interruption. Third, to provide incentives for efficiency in construction and operation of the project.

The essence of this approach is to allow gas producers and project investors to earn profits equal to the market value of the gas less the cost of production and transportation, while assuring a minimum return on investment as long as minimum deliveries are made. Under this financing approach, a cost of service tariff during normal operation would be provided.

The project sponsors will have to assume the risk of total loss of the capital cost of the project, in order to arrange successful private financing. For this reason, it will be necessary to establish a rate of return on equity judged adequate by project sponsors and investors to compensate them both for their investment risk, and for guaranteeing repayment of the debt.

Since the risks of this project may be perceived as greater than those of other gas utility projects previously considered by this Commission, we believe it will be necessary to provide investors an opportunity to earn a higher than usual rate of return. However, we do not favor guaranteeing a high return if the result would be a delivered cost of gas in excess of its market value. Thus, a variable rate of return on equity is appropriate.

The major questions with such an approach are the appropriate maximum and minimum rate of return on equity, and the determination of the rate of return during a particular period.

Unfortunately, the record provides little guidance on these questions other than showing that no party is willing to guarantee the debt at a 72/25 debt to equity ratio and 15-17 percent after-tax return on equity. Our analysis indicates that with an assumed 50/50 D/E ratio, and under current financial market conditions, a maximum 18 percent after-tax rate of return on common equity would appear to be just and reasonable for the project sponsor debt-guarantee financing approach. This return would be allowed so long as the delivered cost of gas (field price + transportation cost) does not exceed the market value of the gas.

However, should the minimum field price plus the transportation cost exceed the market value of the gas, the return on equity would be reduced as necessary to maintain the delivered cost of gas equal to its market value.

To provide investors some protection against the project uneconomic, we would allow a minimum return on equity if a specified level of delivery is maintained. Given the variety of operating risks the project will face, we recommend a minimum return on equity of 11 percent after-tax.

The 11 to 18 percent range provides the incentive for the project sponsors to construct and operate the project efficiently.

Should both the field price for gas and the return on transportation system investment be reduced to their minimum levels, consumers would then pay a price higher than market value for Alaskan gas.

We have no application before us now indicating that private parties are willing to finance the project on this basis; we cannot even be certain that a financial plan such as that described will be presented for approval. Therefore, we must consider alternate means of financing. Furthermore, project sponsor debt guarantees come at a cost. Higher than usual rates of return on equity will be required, and the use of less expensive debt funds may be limited. The alternative is to shift certain risks to consumers or taxpayers.

7. Consumer Debt Guarantee Financing Approach

Measures to protect consumers from bearing unnecessary costs and risks are required for this financing method and it is appropriate to provide realistic compensation for the risks that must be borne. Consumers should not bear a major portion of the project's risk while other parties reap the bulk of the economic benefits.

In our opinion, equity investors should bear the risk of loss of their total equity investment in the event of extended service interruption or noncompletion.

Nevertheless, if the project sponsors are limited to gas utilities, the record demonstrates that consumer guarantees for debt service payments will be required for financing. Given that an Alaskan natural gas transportation system is in the public interest, consumer debt guarantees would be appropriate. Once the project begins operation, such guarantees involve an all-events cost of service tariff, whereby the project could charge gas shippers, and gas shippers could charge their customers, an amount adequate to cover the total cost of service excepting return on and recovery of equity capital in the event of extended service interruption. Before completion, gas shippers would be committed to covering debt service payments in the event that the project was not completed. Federally regulated gas shippers would be authorized to flow through such payments to their customers on a current basis.

The financial risk to the project sponsors is thus substantially reduced. For example, with a 75/25 debt equity ratio, the sponsors' risk in the case of noncompletion or interruption is one-fourth the amount under the other financing approach.

We believe that if consumers are required to bear a major portion of the risks, they should also pay lower rates than if others were bearing these risks.

If consumer debt guarantees prove to be necessary in attracting private financing, and the proposed formula approach to establishing the field price for Alaskan gas is adopted, we recommend adoption of a consumer guarantee fee. The guarantee fee would equal the difference between the cost of service under the project sponsor debt guarantee approach and the cost of service with consumer guarantees. In calculating the gas field price, the consumer guarantee fee would be added to the out-of-pocket transportation cost. Thus, the allowed field price would be approximately the same whether the "Sponsor" or "Consumer" Debt Guarantee approach is used. However, since the delivered cost of gas is equal to the sum of the field price for gas plus the out-of-pocket transportation cost, consumers would receive gas at a delivered cost lower than market value, as compensation for their risk bearing.

We recommend that if consumer debt guarantees are required, the rate of return on equity investments should be similar to that under the first approach, except that the maximum rate of return would be 15 percent and the minimum return would be 11 percent.

Assuming a $10 billion capital cost, a gas flow rate of 2.25 Bcfd, and the financial arrangement discussed above, the first year consumer guarantee fee would be approximately $0.97 per Mcf in nominal dollars or $0.66 per Mcf in 1975 dollars. Such a fee would be equal to approximately 11 percent of the project's outstanding debt.

Arctic Gas argues, and Judge Litt concurs, that some type of surcharge on gas consumers is needed to provide adequate cash flow to cover the carrying cost on investments during the construction period. Such surcharges would take the form of consumer loans with a clear obligation for repayment with interest, even in the case of project failure.

In general, we believe that if the currently proposed group of project sponsors do not have the capacity to finance the required equity investment, additional participants should be added to the consortium so as to permit traditional financing. Nevertheless, given the size of the project and the potential for cost overruns, we can envision circumstances under which such a surcharge could be in the public interest.

One obstacle to the use of such consumer surcharges is the tax treatment of such money to the gas shippers and distribution companies. If these funds are treated as taxable income, rather than as loans, then the size of the required surcharge would approximately double. Solution of this tax problem is a prerequisite to adoption of this approach.

The all events tariff, noncompletion agreement, and consumer surcharge represent a new level of financial risk bearing by gas consumers. In effect, consumers are either guaranteeing the repayment of the project's debt financing, or making investments directly in the project. In our opinion, this approach depends substantially on measures to protect consumers from bearing unnecessary costs and risks.

We believe the project must be structured so the impact on gas consumers of project failure is tolerable. If required, we could require a reasonably broad distribution across domestic markets.

In addition, as previously noted, we would expect the project's equity investment to be at risk in the case of noncompletion or service interruption.

Federal regulatory authorities should also retain the residual power to terminate prospectively the all events cost of service tariff, consumer surcharges should it become uneconomic to complete the project. All parties concerned will undoubtedly require the establishment of objective standards for determining when Federal regulatory authorities would be empowered to terminate the tariff arrangements.

Finally, the viability of the project requires substantial quantities of gas for shipment. It would be desirable to have contractual commitments by the producers regarding the minimum average daily volume that will be delivered to the shipper so that the extent of the consumer's risk can be better assessed.

The successful applicant's books should be audited during the construction period to insure that costs are prudently incurred and properly recorded. We further propose that the Commission would periodically decide which construction costs were recoverable through the project's tariff. However, under the sponsor debt guarantee financing approach, a Commission certification that certain costs were prudently incurred would not imply that such costs could be recovered from consumers in the event of noncompletion or extended service interruption.

Certain legislation would reduce the level of regulatory risk faced by project sponsors and investors, reducing cost of capital, and improving financeability. If all events cost of service tariffs, and/or noncompletion agreements are required, we would support legislation to bind future Federal regulatory authorities to maintain and enforce such arrangements. Subject to reserving the right to review whether costs were prudently incurred, we would support the passthrough of costs on a current basis and support legislation binding Federal regulatory authorities to maintain this treatment.

We believe it is essential to maintain a dialogue with state utility commissions to discuss financing alternatives. It may prove useful for the Government to sponsor a conference in the near future to consider the issues of regulatory risk at the State level, and possible State actions. A principal topic of discussion would be alternatives to, and the need for, Federal legislation to assure the flow through of approved costs at the distribution company level.

8. Financial Plan Feasibility

Each applicant has submitted financial testimony that, with adequate credit backing, its project can be financed in the private capital markets. We agree with Judge Litt that given ". . . the different guidelines that are certain to be in place when the successful applicant seeks to firm up final financial plans for Commission approval, the detailed record discussion of the feasibility of existing plans takes on less significance." This conclusion clearly applies if the sponsor debt guarantee financing approach attracts additional creditworthy parties, and the project's debt to equity ratio is decreased significantly.

Given adequate and identical tariff provisions, the El Paso financing plan appears to be the most feasible. In particular, the anticipated availability of Title XI, Federal ship financing guarantees will increase El Paso's access to loans from U. S. pension funds. Further, El Paso does not have to contend with the issue of the so-called "Canadian Basket" under which U. S. life insurance companies are limited in their overall ability to make investment in Canadian companies. However, El Paso's greatest advantage may be that it would operate solely under American regulation. Operating under a single regulatory authority facilitates innovations which may prove to be essential in arranging a private financing.

The proposed Arctic Gas financing plan would press the limits of certain U. S. and Canadian capital markets, it would appear that a successful financing could be accomplished if adequate credit backing for the project's debt financing is available.

Of the three applicants, Alcan's financing plan has been the subject of the greatest criticism. A principal attack has been that both the Alcan and Maple Leaf projects cannot be financed during the same time period, and that one or the other of the projects may have to be delayed. If Alcan suffers such a delay, any related cost increase would have to be absorbed by U. S. consumers.

A second basic attack on the Alcan financing plan is the proposal that U. S. shippers supply over 50 percent of the equity for the Foothills and Alberta Gas Trunk Line segments in exchange for nonvoting stock which some potential shippers consider inferior. We do not intend forcing U. S. shippers to accept such a proposal. The project sponsors must work out a satisfactory compromise if the final Alcan financing plan is to be found acceptable.

O. Major Comparative Advantages and Disadvantages

The proposed systems can be compared along the major dimensions discussed in this recommendation.

1. Economics

Arctic's proposal is economically superior to those of the other applicants. Arctic's average national cost of service for the first 20 years of operation is $.76 per MMBtu in 1975 dollars, compared to Alcan's $.79 per MMBtu, and El Paso's $1.09 per MMBtu. 43/ We have expressed our belief that Alcan is not likely to meet its projected schedule and that the consequent delay would raise the average cost a few cents. We have also questioned Alcan's labor productivity in Canada. If their productivity is equal to Arctic's, the cost of service would rise a few cents. 44/

Alcan and Arctic do not differ significantly in net national economic benefit (NNEB). El Paso's NNEB is lower, but its percentage disadvantage is less than on the cost of service comparison. All three systems exhibit a large net national economic benefit, which even extensive cost overruns would not wholly erase.

Arctic is the most likely to suffer substantial cost overruns, due to potential construction delays in completing its North Slope section. Our analysis, however, indicates that even with a $270 million cost overrun in the Prudhoe Bay lateral section and a one-year delay before commencement of service from Prudhoe Bay, the unit cost of service would

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43/ Both Arctic's and El Paso's costs are likely to be overstated a small amount. We believe El Paso made an error in the *ad valorem* tax component of its cost estimates. Arctic's costs were based on 2.25 Bcfd flow rate compared to 2.4 Bcfd for El Paso and Alcan. A higher flow rate for Arctic would lower its cost of service a few percent.

44/ Conversely, if Arctic's productivity were increased to the level of Alcan's, Arctic's cost of service would decrease.

increase only 12 percent, from \$.76/MMBtu to \$.85/MMBtu. We believe this is an extreme assumption and do not anticipate its occurrence.

Neither El Paso nor Alcan appear to be subject to large cost overruns due to the forces of man or nature, even if Alcan's costs are recalculated to meet our above-stated reservations about schedule and productivity.

Both Alcan and Arctic can expand inexpensively from the initial flow rate of 2.25 Bcfd by adding compression. By comparison, in order to expand deliveries, El Paso's LNG tankers, liquefaction and regasification facilities must all be scaled-up at costs roughly proportional to their initial costs.

2. Environmental Impacts

Both Arctic and El Paso pose environmental problems greater than those created by Alcan. We find that Arctic's proposed method of crossing the Arctic National Wildlife Range and the Mackenzie Delta can be done with acceptable environmental impacts. We also find that El Paso's construction through the Chugach National Forest, and its potential thermal impact on Prince William Sound, would also be environmentally acceptable with proper mitigative measures. On balance, however, we find Alcan's route preferable from an environmental standpoint. The use of existing utility corridors and all-weather roads over much of its route means that Alcan's construction and operating impact is less than if these corridors and roads were not already in place.

3. System Reliability and LNG Safety

Natural gas pipelines are among the most reliable of all transportation systems. While permafrost conditions require chilling the gas and this, in turn, creates some geotechnical problems, these problems do not appear to seriously threaten the reliability of any of the proposed pipeline systems.

El Paso's more complex LNG processing and transportation system, and the siting of its processing facilities in high seismic areas, make it subject to a slightly higher risk of service interruption. We believe, however, that these risks are small and would result in only temporary and partial disruption of service.

El Paso also presents the risk of hazard to a limited population should there be an LNG accident. However, the technology for handling LNG is well developed, and we believe that the probability of an accident is low. If an accident should occur, damage to human life will be minimal.

4. Financeability

El Paso holds a distinct advantage over Arctic and Alcan with respect to ease of obtaining financing. El Paso has the lowest capital costs by a small margin. Even considering the likelihood of cost overruns for all three systems, El Paso remains superior. Thus, it would have the least impact on capital markets.

Furthermore, United States Government guarantees are available to El Paso under Title XI of the Merchant Marine Act of 1936. El Paso believes its LNG fleet can be financed with triple-A bonds at the lowest possible costs because of these guarantees. Thus, 20 percent of its total capital requirements are easily and cheaply obtained (although some risk is borne by the United States Government).

CHAPTER II

DESCRIPTION OF PROPOSED TRANSPORTATION SYSTEMS

A. Introduction

This chapter describes the three systems proposed for transporting Alaska North Slope gas to U.S. markets. One proposed system would also transport Mackenzie Delta gas from Northwest Canada to Canadian markets. The proposed transportation systems are:

- The Arctic Gas System
- The El Paso Alaska System
- The Alcan System
  - Original 42-inch System
  - Alternative 48-inch System

A more detailed description of the rival systems including especially the evolution of each system now proposed and various route alternatives, can be found in Appendix A of the Initial Decision and the FPC staff document entitled "A Staff Report to the Commission Pursuant to Order No. 558-C on the Alcan 48-Inch Project Filed March 8 and March 22, 1977, And the El Paso Project Fleet Size," April 8, 1977. 1/ The hearing record and filings made subsequent to the close of the hearing, of course, contain detailed information on all aspects of the systems.

1/ Most of the information presented in this chapter was extracted from these two documents.

B. Arctic Gas System

1. Basic Proposal

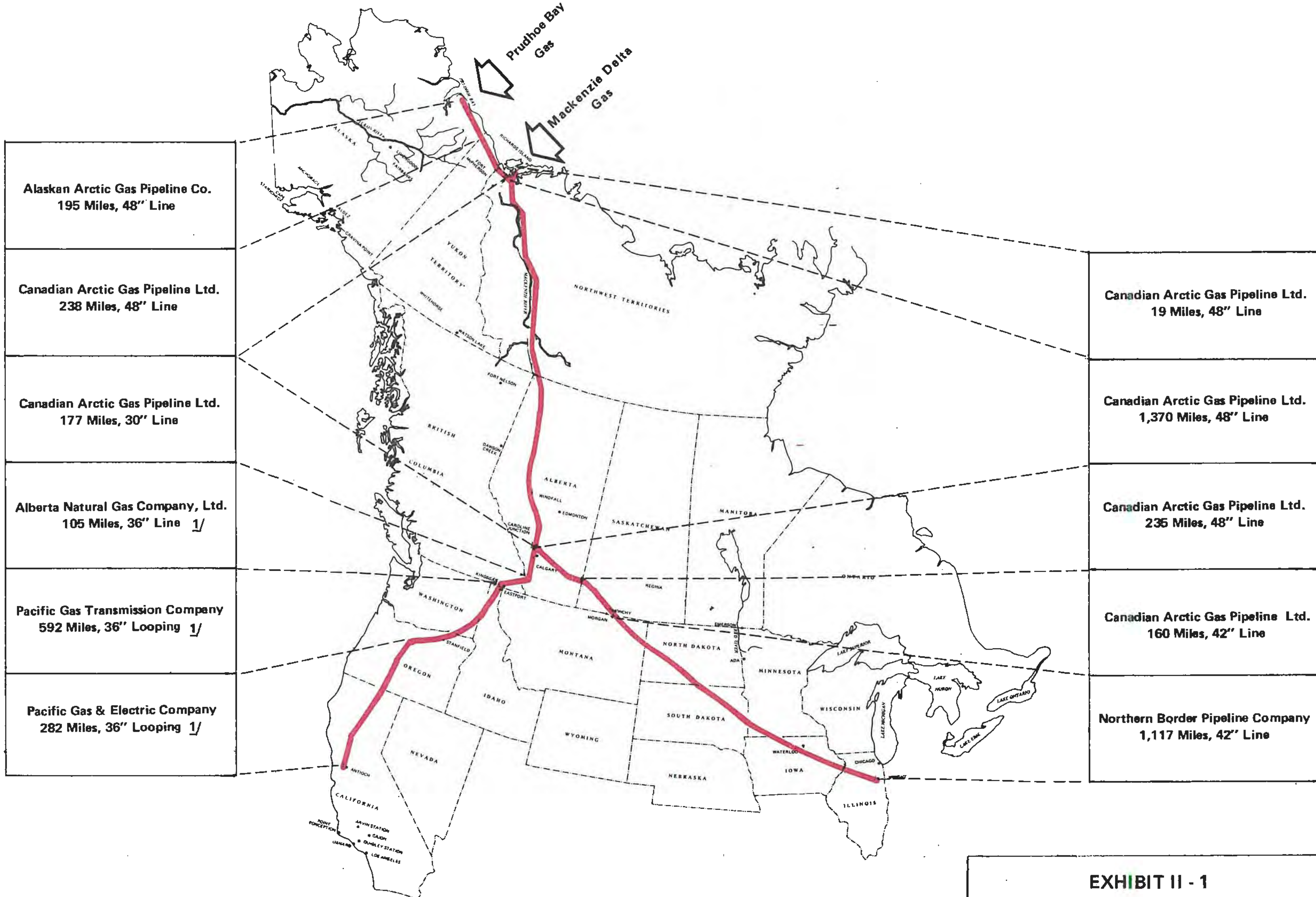
a) Location of Facilities and Companies Involved

The Arctic Gas System (Arctic) proposes to construct a buried, overland natural gas pipeline extending from the Prudhoe Bay Field on the North Slope of Alaska and the Mackenzie Delta area of northwestern Canada to market areas of Canada and the United States. The following six companies, four American and two Canadian, have applications pending with appropriate agencies to obtain permits to construct and operate this system: Alaskan Arctic Gas Pipeline Company (Alaskan Arctic), Canadian Arctic Pipeline Company Limited (Canadian Arctic), Northern Border Pipeline Company (Northern Border), Pacific Gas Transmission Company (PGT), Pacific Gas and Electric Company (PG&E), and Alberta Natural Gas Company Ltd. (Alberta Natural).

The total length of the pipeline system would be approximately 4,512 miles, with the various applicants operating the segments depicted in Exhibit II-1. The pipeline would be operated at a maximum pressure of 1,680 psig. The portion of the pipeline in the continuous and discontinuous permafrost zones would be operated as a chilled gas system by installing refrigeration units at the discharge side of the compressor stations. The temperature of the gas would be maintained between 32°F and -10°F.

Alaskan Arctic would construct a 48-inch diameter chilled gas pipeline extending from Prudhoe Bay Field along the coastal plain of the Arctic National Wildlife Range (ANWR) to the Alaska-Canada border.

From the Alaska-Canada border the pipeline would continue east along the Beaufort Sea coast and cross the



1/ See Chapter IX For Detail Description of "Western Leg"

EXHIBIT II - 1

DESCRIPTION OF ARCTIC GAS PIPELINE PROJECT

outer Mackenzie Delta, where it would interconnect at Tununuk Junction with a 19-mile, 48-inch supply line running south from Richards Island. The Delta crossing would employ twinned 36-inch lines for 36.5 miles. (See Exhibit I-1).

From Tununuk Junction, the 48-inch main line would extend south to Caroline Junction, Alberta. At Caroline Junction the line would divide. A 30-inch western leg would run south to the Alberta-British Columbia border connecting with expanded facilities of Alberta Natural which continue south to Kingsgate, British Columbia. An eastern leg would run to Monchy, Saskatchewan; the line size would be 48-inch to Empress, Alberta, and 42-inch from Empress to Monchy. The complete Canadian section of the Arctic Gas System would total 2,305 miles.

To carry gas to the U.S. Midwest, six U.S. pipeline companies have created the Northern Border Pipeline Company. 2/ This partnership proposes to construct and operate a 1,117-mile long, 42-inch diameter pipeline extending to a terminus at Dwight, Illinois. (See page XI-1, footnote 1.) The pipeline would be operated at a pressure of 1,435 psi. Based upon an input volume of 1.53 Bcfd 3/ eight compression stations would be required. The capacity of the system could be expanded to receive 2.12 Bcfd with increased Prudhoe Bay inputs by the addition of eleven compressor stations. 4/ Numerous connection points would remain to be installed along the 1,117-mile pipeline from the U.S.-Canadian border to near Dwight in order to facilitate delivery of gas to companies serving areas east of the Rocky Mountains.

2/ Columbia Gas Transmission Corp., Michigan Wisconsin Pipe Line Co., Natural Gas Pipeline Company of America, Northern Natural Gas Co., Panhandle Eastern Pipe Line Co., and Texas Eastern Transmission Corp.

3/ This figure is derived from a 2.25 Bcfd input at Prudhoe Bay and an approximate 70/30 split between the eastern and western leg.

4/ Ref: Exhibits NB 22 through NB 26.

The method by which Alaskan gas would be delivered to the western states is discussed in Chapter IX.

b) Volumes to be Transported

Arctic projected gas deliveries from the Alaska North Slope of 2 Bcfd after one year of operation and 2.25 Bcfd after five years. The applicant also projected initial gas deliveries from the Mackenzie Delta area of 1.25 Bcfd increasing to 2.25 Bcfd in the fifth year of operation.

As currently proposed, the delivery capacity of Northern Border to the midwestern and eastern sections of the United States would be 1.5 Bcfd. The capacity of the PGT/PG&E pipeline, if completely looped as currently proposed, would be 659,000 Mcf/d (See Chapter IX). Therefore, the probable combined delivery capacity of the pipelines in the 48 contiguous states would be 2.159 Bcfd. If additional gas volumes are made available, these system capacities could be increased by additional compression and/or pipeline looping.

c) Related Facilities

Pipeline laterals and other gas gathering and separation facilities in the Prudhoe Bay area would be constructed by the oil companies. No compressor facilities would be constructed on the 195-mile long pipeline in Alaska until available gas volumes increased beyond 2.25 Bcfd. At that time, Alaskan Arctic would install four compressors and gas chillers along the North Slope portion of the line. Other ancillary facilities required for the pipeline in Alaska include seven material stockpipe sites (four of which would be located at possible future compressor station sites), two seaport areas in addition to the Prudhoe Bay port facilities, 16 aircraft facilities, approximately 250 miles of temporary snow-ice roads, field operating headquarters at Prudhoe Bay, and operations headquarters in Anchorage.

d) Construction Schedule

Most companies propose to start construction approximately 1 year after final approval is received. Construction would be conducted concurrently on all pipeline segments with the timing of approval and construction of the Canadian segment a critical factor in any overall projection of delivery.

According to Arctic, the construction of the gas pipeline in Alaska, including related facilities, would be phased over a 3-year period. Most construction work is planned to occur during the winter months, from November to April, and snow roads would be used to provide access throughout the pipeline construction area.

In Canada, the construction of the pipeline and related facilities and supply lines would be phased over several years. Actual pipeline laying would begin late in the second construction year and be completed in the fifth construction year.

The Northern Border portion of the line would be completed in approximately 51 months. No winter construction is contemplated, and most work is proposed to be accomplished between May and November. It is anticipated that construction may be curtailed during March and April because of vehicle weight restrictions imposed on roads in this area of the Northern U.S. during this spring season.

The general plan for PGT/PG&E would be to start construction on the western leg after approvals are received and 36 months prior to initial flow of gas.

C. El Paso Alaska System

1. Basic Proposals

El Paso Alaska Company (El Paso) would transport natural gas from the Prudhoe Bay Field through approximately 809 miles of 42-inch buried chilled gas pipeline to a gas liquefaction plant and terminal located on Prince William Sound at Point Gravina, Alaska. There, the gas would be converted to liquid natural gas (LNG) 5/ and then shipped via cryogenic tankers, 1,900 nautical miles (approximately 2,200 statute miles) to a receiving terminal and regasification facility on the southern California coast near Point Conception in Santa Barbara County. From there, the revaporized gas would be transported by a pair of proposed 142-mile, 42-inch parallel pipelines to existing mainline delivery facilities at Arvin Station, California, and then from Arvin Station via a proposed 109-mile, 42-inch pipeline to Cajon, California, for further distribution. See Exhibit II-2. The Point Conception terminal and related pipeline facilities would be constructed by the Western LNG Terminal Company (Western LNG). 6/

The proposed pipeline through Alaska would essentially follow the Alyeska oil pipeline from Prudhoe Bay to a point north of Valdez. Although both pipelines would be located in a common "utility corridor" they would not be located within a common right-of-way. As a result, the El Paso Alaskan route would traverse non-impacted terrain, with 85 percent of the route being located within 3,000 feet of the existing oil pipeline. The remainder of the proposed route and the LNG terminal would be located in sections of the essentially undisturbed Chugach National Forest in Alaska. Most of the pipeline would be constructed in winter.

The proposed Point Conception terminal would be located in a relatively undisturbed area of the southern California coastline. The Oxnard alternative is more industrialized.

5/ By chilling natural gas to minus 259 degrees Fahrenheit, the gas becomes a liquid (LNG), and it reduces in volume by approximately 600 fold.

6/ There is some controversy related to whether Point Gravina and Point Conception are the best locations for the Alaska and California facilities, respectively. The alternative to Point Gravina is Cape Starichkof which lies approximately 100 miles west of Point Gravina on Cook Inlet. The alternative California terminal is Oxnard, about 70 miles south of Point Conception. See Chapter VII.

Proposed 3.2 BCF/D System	Alternate 2.4 BCF/D System
El Paso Alaska Company 809 Miles, 42" Line	El Paso Alaska Company 809 Miles, 42" Line
El Paso Alaska Company Eight - Train LNG Plant	El Paso Alaska Company Six - Train LNG Plant
El Paso Alaska Company Eleven - 165,000 CuM Tankers 1900 Nautical Miles (2200 Statute Miles)	El Paso Alaska Company Eight - 165,000 CuM Tankers 1900 Nautical Miles (2200 Statute Miles)
Western LNG Terminal Co. LNG Regasification Plant	Western LNG Terminal Co. LNG Regasification Plant
Western LNG Terminal Co. 142 Miles, Twin 42" Lines 109 Miles, 42" Line	Western LNG Terminal Co. 142 Miles, Twin 42" Lines 109 Miles, 42" Line

EXHIBIT II - 2

DESCRIPTION OF EL PASO - ALASKA PROJECT

2. 3.2 Bcfd Case

a) Gas Volumes to be transported

The proposed El Paso pipeline would receive 3.190 Bcfd at Prudhoe Bay and would deliver 3.103 Bcfd to the liquefaction plant at Point Gravina. The proposed revaporization facility at Point Conception would subsequently receive approximately 2.809 Bcfd and revaporize at a rate of 2.803 Bcfd with an additional peaking capacity of 0.30 Bcfd. This gas would then be delivered to existing mainline pipeline systems via the proposed pipelines to be constructed to Arvin Station and Cajon, California.

b) Related Facilities

The proposed 809-mile pipeline through Alaska would have a maximum operating pressure of 1,670 psig and utilize twelve compressor stations. Each station would have 46,800 installed gas compressor horsepower. In addition, 11 of the 12 stations would have refrigeration facilities to chill the gas.

The proposed gas liquefaction facility would require approximately 450 acres of land. The LNG plant would be composed of gas treating, dehydration, and liquefaction facilities. Additionally, LNG storage facilities and a marine terminal would be required.

The LNG plant would contain eight independent parallel processing trains, each having an inlet design flow rate of 421.88 MMcfd, adequate to process the 3.103 Bcfd feed gas deliveries to the plant. Such processing will result in LNG deliveries to the carrier fleet equivalent to 2.864 Bcfd of gas. The process known as the "Phillips Optimized Cascade Cycle" will be used to liquefy the gas. Four 550,000 barrel cryogenic storage tanks will hold the LNG.

El Paso modified its original LNG plant design to effect an anticipated 34.1 percent fuel savings in plant operation. This design, sometimes called "MOD POD," if effective, would reduce plant fuel consumption from 289.25 billion Btu/d to 190.70 billion Btu/d.

The proposed LNG tanker terminal at Gravina would be located 1,200 feet offshore in Orca Bay. At this location, Orca Bay is approximately six miles wide, with waters in the immediate vicinity ranging in depth from 50 to 300 feet. This terminal would be constructed to handle the loading of two LNG tankers at once. 7/

El Paso proposed to build eleven 165,000-cubic meter double-hull LNG carriers. These tankers would be equipped with either free standing or membrane tanks insulated to carry the LNG cargo. Each of the carriers would have an average service speed of 18.5 knots and should be capable of completing the round trip voyage of 3,804 nautical miles between the Alaskan liquefaction and California regasification facilities in approximately twelve days including delays. With each ship operating 345 days per year, the fleet would transport 316 shiploads of LNG annually to the proposed regasification plant at Point Conception, 70 miles north of Oxnard and 120 north of Los Angeles. Each of the 11 ships will be constructed in American yards.

The regasification facility would be constructed by Western LNG. These facilities would unload LNG, store it in double-walled insulated tanks, and withdraw and revaporize it for delivery into proposed gas transmission pipelines.

The marine berthing and unloading facilities at Point Conception would be located about 4,600 feet offshore and would accommodate and simultaneously unload two LNG ships of up to 165,000 cubic meters capacity.

7/ See Chapter VII for discussion of plant location.

A cryogenic LNG transfer system would be required to carry the LNG from ship to onshore storage tanks. This system would consist of two parallel stainless steel 36" diameter insulated cryogenic lines and one 20" diameter vapor return line. This system would be approximately 6,000 feet long; 4,600 feet would be mounted on a trestle in the offshore area, and 1,400 feet would be installed above ground on the plant site.

The terminal would have a design baseload sendout rate of 2.803 Bcfd with a 3.103 Bcfd peaking capacity. Western LNG has proposed to construct a pair of 142-mile long, 42-inch pipelines from Point Conception to Arvin, California, and a 109-mile long, 42-inch pipeline from Arvin to Cajon, California. The revaporized LNG would be transported to existing mainline gas transmission systems owned by Pacific Gas and Electric Company and Southern California Gas Company.

In addition to the facilities described above, El Paso Alaska has described in detail facilities necessary to deliver by displacement 2.06 Bcfd of the 3.1 Bcfd peak day supply to markets east of the Rocky Mountains. 8/

c) Construction Schedule

According to El Paso, construction of the pipeline across Alaska and the LNG facility at Gravina would require an estimated 5 years to complete. Three of the ships would be completed by the end of the fifth year and the remainder during the sixth. The overall construction period for the Point Conception facilities would require 44 months. Total time to construct the related California pipelines would be less than 26 months. 9/

8/ See Initial Decision, pages 280-85 for description of El Paso's displacement plan.

9/ Construction schedule estimates taken from "Initial Brief of El Paso Alaska With Respect To Cost, Scheduling and Economics," pp. 49-54. The Initial Decision indicated an overall construction period of 6½ years, to which El Paso objected strongly (Brief on Exception).

3. 2.4 Bcfd Case

El Paso filed an alternative showing which described the facilities which would be required for the transportation and liquefaction of 2.4 Bcfd. The required pipeline facilities are essentially the same as those in the 3.2 Bcfd case, with the exception of that the number of compressor stations is reduced by two, and the installed horsepower in each of the remaining 10 stations is reduced by half to 23,400. Auxiliary systems remain the same. The reduced natural gas flow also reduces refigeration load requirements. The only significant difference in the LNG plant is that it becomes a six-train plant with an inlet volume of 2.327 Bcfd. The six-train alternative design is readily expandable to the 3.2 Bcfd case eight-train LNG plant design. Each of the six independent, parallel processing trains will have an inlet design flow rate of 421.88 MMcfd. The plant would permit LNG deliveries to the LNG carrier fleet equivalent to 2.147 Bcfd of natural gas.

The Alaskan marine terminal facilities required for the 2.4 Bcfd case remain unchanged, and El Paso proposed to use only eight LNG tankers. Each tanker would operate 345 days per year and a total of 233 shiploads of LNG would be transported annually from Gravina Point to Point Conception, California. Based on LNG plant production of 2.147 Bcfd, the fleet would deliver the LNG equivalent of 2.106 Bcfd.

4. Realignment Case

El Paso has also filed evidence in support of the realignment of its Alaskan pipeline facilities to bring its proposed line closer to the existing Alyeska haul road and facilities. This submission was prompted by testimony of the Pipeline Coordinator for the State of Alaska stating that the office preferred to see the gas pipeline more closely adjacent to the oil pipeline to lessen environmental impact.

As a result of the realignment, the gas pipeline would be about 13.8 miles longer. Other than relocation, there are no changes in the design of any of the compressor stations. No changes have been made in the LNG plant, the Alaskan marine terminal or in the LNG carrier fleet. The realigned pipeline can be utilized for either the 3.2 Bcfd or the 2.4 Bcfd throughout. Unless certain waivers are received from the U.S. Department of Transportation's Office of Pipeline Safety, the portion of the pipeline closer to the haul road would have to be operated at decreased pressure, or thicker-walled pipe would have to be installed.

D. Alcan System

1. Original 42" Proposal

In their original applications Alcan and Northwest Pipeline Corporation (Northwest) proposed to construct and operate in the United States 1,090 miles of 42- and 30-inch diameter natural gas pipeline, 10/ 16 new compressor stations (15 in Alaska and 1 in Washington), and additions at eight existing compressor stations in the northwestern United States.

This "Alcan I" project would deliver natural gas from the Prudhoe Bay area of the North Slope of Alaska to markets in Alaska and in the lower 48 states. 11/ See Exhibit II-3. As proposed, 2.4 Bcfd of gas would be transported by Alcan from Prudhoe Bay to the Alaskan-Yukon Territory (Canada) border, less the amount delivered to Alaskan markets (approximately 44,100 Mcfd) or utilized in transmission. In Alaska the pipeline would parallel the Alyeska Oil Pipeline to Delta Junction approximately 50 miles southeast of Fairbanks, where it then follows the Alaska Highway to the Yukon Border. From the border a Canadian company,

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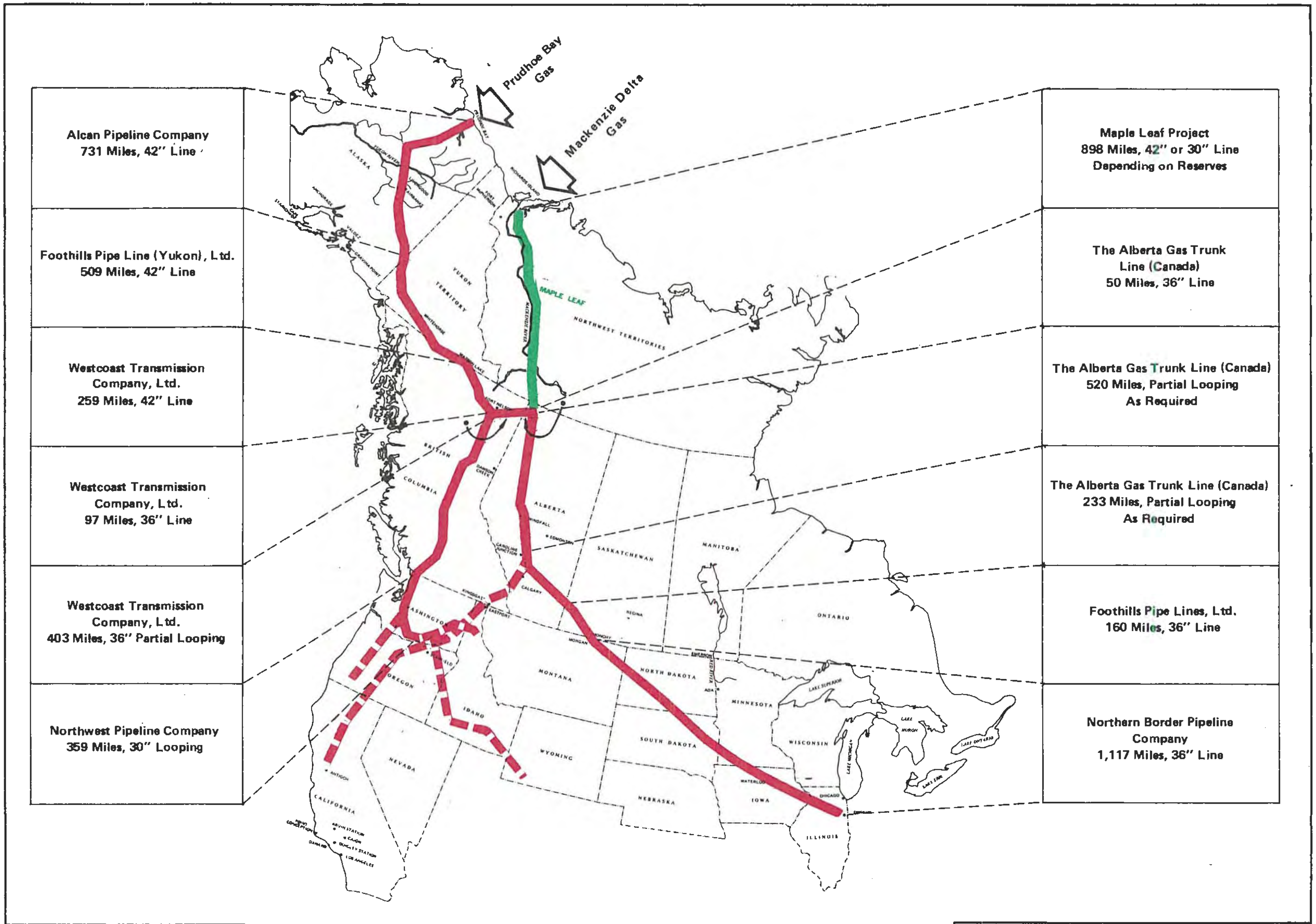
10/ Alcan would construct 731 miles of new 42-inch line in Alaska, and Northwest would construct 359 miles 30-inch looping in Washington.

11/ The proposed Canadian Maple Leaf System would transport Mackenzie Delta gas (See Exhibit II-3).



Legend

Existing Pipelines

NOTE: Maple Leaf Project is Sponsored by Foothills, Westcoast, and Alberta Gas Trunk Line.

EXHIBIT II – 3

DESCRIPTION OF
ALCAN PIPELINE PROJECT
(42" ORIGINAL)
AND MAPLE LEAF PROJECT

Foothills Pipe Lines Ltd. (Foothills), or an affiliate thereof, would transport the gas to the Yukon Territory-British Columbia border near Watson Lake. There the remaining volumes would be delivered to Westcoast Transmission Company Limited (Westcoast) which would transport the gas to a point of interconnection with their existing facilities at Fort Nelson, British Columbia. At Fort Nelson, approximately 30 percent of the gas would be transferred into existing and new facilities of Westcoast and transported to existing facilities of Northwest at Sumas, Washington. The volume delivered at Sumas would be approximately 669,000 Mcfd. From Sumas, the gas would be transported approximately 359 miles south and east through existing and new Northwest facilities to a new interconnection with Pacific Gas Transmission Company (PGT) at Kent, Oregon.

The remaining 70 percent of the gas would be transported by Westcoast from Fort Nelson to a point of interconnection with new facilities of Alberta Gas Trunkline (AGTL) at the Alberta-British Columbia border. AGTL would then transport the volumes of gas received from Westcoast to a point of interconnection with the existing facilities of AGTL near Zama Lake, Alberta, and then on to Caroline Junction, Alberta, where a division of the gas volumes would be made for delivery to two different points on the Canadian-United States border. 12/ One portion would be transported to the existing facilities of Alberta Natural Gas Company, Limited (ANG) in the vicinity of Coleman, Alberta. These volumes would then be transported by ANG to the existing facilities of PGT on the Canadian-United States border at Kingsgate, British Columbia. The gas volumes delivered at Kingsgate would total approximately 191,000 Mcfd.

12/ The existing AGTL facilities in Alberta would be expanded by AGTL to increase transmission capacity.

The remaining gas at Caroline Junction would be transported to the Alberta-Saskatchewan border in the vicinity of Empress, Alberta, where the gas would be delivered to Foothills. Foothills would transport the gas to the Canadian-United States border at Monchy, Saskatchewan. Approximately 1.342 Bcfd would be delivered to the proposed facilities of Northern Border Pipeline Company (Northern Border) at Monchy.

2. Alternative 48" Proposal (Alcan II)

The Alcan II proposal would provide a 48-inch pipeline extending from Prudhoe Bay to James River (Caroline), Alberta. From James River, gas destined for eastern U.S. markets would be transported through a separate high-pressure 42-inch pipeline to Monchy, Saskatchewan, for delivery to the proposed Northern Border pipeline system. Gas destined for western U.S. markets would be transported from James River (Caroline), Alberta, through a separate 36-inch pipeline for delivery at Kingsgate, British Columbia, to PGT. See Exhibit II-4. The initial design of the 48-inch diameter pipeline system would achieve an annual average daily capacity of 2.4 Bcfd. Annual average daily capacity of the system, achieved by the installation of additional compressor stations, would be 3.2 Bcfd.

The route of the Alcan II 48-inch pipeline alternative would be the same in Alaska as that initially proposed by Alcan I. It would parallel the Alyeska oil pipeline from Prudhoe Bay to Delta Junction, Alaska. At Delta Junction the pipeline would diverge from the Alyeska oil pipeline system and follow the Alaska Highway and the Haines products pipeline rights-of-way in a southeasterly direction to the Alaska-Yukon border. The facilities in Alaska would be owned and operated by Alcan.

At the Alaska-Yukon border, natural gas would be delivered to Foothills which would construct and operate facilities paralleling the Alaska Highway to a point on the Yukon-British Columbia border near Watson Lake, Yukon.

1/ SEE CHAPTER IX FOR DETAIL DESCRIPTION OF "WESTERN LEG"

EXHIBIT II - 4

DESCRIPTION OF

ALCAN PIPELINE PROJECT

(48" ALTERNATIVE)

At the Yukon-British Columbia border the gas would be delivered to Westcoast which would transport the gas through British Columbia generally along the Alaska Highway to the Alberta border near Boundary Lake.

At the Alberta-British Columbia border the gas would be delivered by Westcoast to AGTL which would construct a pipeline through Alberta parallel to the existing AGTL system from near Gold Creek to James River (Caroline), Alberta.

At James River, the pipeline system would split with one leg following the AGTL existing system to Empress, Alberta, on the Alberta-Saskatchewan border. The route for the western leg would parallel the AGTL existing system from James River to Coleman, Alberta, on the Alberta-British Columbia border.

The route for the delivery of the gas to the Midwest U.S. and East would continue southeasterly from Empress, Alberta, through Saskatchewan and to the Canadian-U.S. border at Monchy, Saskatchewan, where the gas would be delivered to Northern Border. This portion of the system would be owned and operated by Foothills (Saskatchewan).

The system for delivering gas to the Western U.S. (the "Western Leg") is discussed in Chapter IX.

Alcan anticipates that service would commence October 1, 1981, with an average daily volume of 1.6 Bcfd from Prudhoe Bay, and anticipates increasing to 2.4 Bcfd by January 1, 1983. System design is based upon an assumed division at James River of 29 percent west to Kingsgate and 71 percent east to Monchy.

The entire system in Alaska as well as the initial 41 miles of pipeline in the Yukon would be operated in a chilled state to minimize degradation of the ice-rich soil (perma-frost). Aerial coolers, located at compressor stations in Alberta and Saskatchewan, would also be employed.

The overall pipeline system would require 30 compressor stations in the final construction year, with 25 of these stations located along the 48-inch diameter main line and 5 on the two delivery legs. Operating pressure of the pipeline in Alaska and Canada is designed for a maximum of 1,260 psig. Delivery pressure into the PGT system at Kingsgate would be approximately 845 psig. At Monchy, delivery pressure to the proposed Northern Border pipeline system would be 1,440 psig.

Alcan proposed to construct its 48-inch pipeline using the same basic concept and techniques as proposed in its 42-inch pipeline proposal. Alcan II would utilize staging areas established for the Alyeska project at Prudhoe Bay, Fairbanks, and Valdez. Material storage sites would also be located at Anchorage, Seward, and Whittier, and at selected locations on the pipeline route.

Alcan would utilize existing Alyeska camp facilities at existing locations where feasible and would relocate existing Alyeska camps from sites not required to two locations in the Delta Junction-Yukon border segment.

A gravel workpad concept is included in Alcan's plan and construction is scheduled from March to November in such a way to protect sensitive species and locations.

CHAPTER III

GAS RESERVES AND DELIVERABILITY

A. Introduction

In this chapter we report on the volumes and producibility of natural gas deposits in the North Slope, the Alaskan interior and Canada's Mackenzie Delta, an obviously crucial consideration in approving a gas transportation system. We include the Mackenzie Delta area because one of the proposed transportation systems, Arctic Gas, would link the North Slope and the Delta in a common system. (See Exhibit III-1).

Clearly, the North Slope's proved reserves and future gas potential justify a gas transportation system. The in-place gas volumes in the Prudhoe Bay Field alone are in excess of 35 Tcf. 1/ Additional gas is expected to be found elsewhere on the North Slope.

The points at issue are (1) how much gas can be delivered from the Prudhoe Bay Field by the time a transportation system is ready; (2) how much additional gas may be available from other North Slope locations and therefore how much weight must be given to these possible supplies in determining the amount of expansion to build into the system; and (3) the effect of potential Mackenzie Delta supplies on the amount of Alaskan gas which the Arctic Gas proposal could deliver to the lower U. S. and the system expansion these potential supplies dictate.

The Alaskan areas whose natural gas potential are examined in this chapter include the Prudhoe Bay Field,

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1/ Most recent estimates put the in-place gas volumes in excess of 40 Tcf. See Section C.

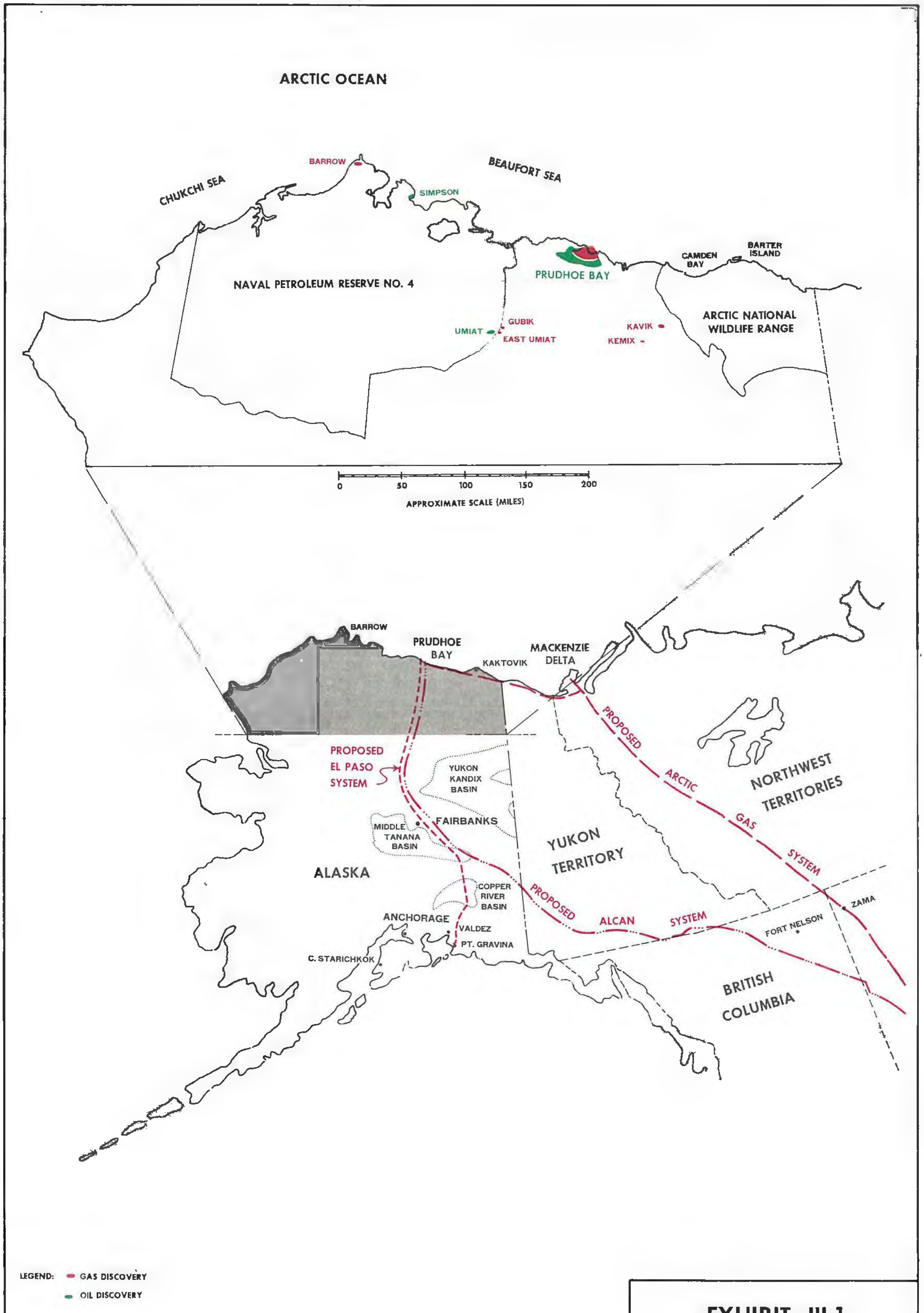

EXHIBIT III-1

AREA LOCATION MAP

Naval Petroleum Reserve No. 4, the Alaskan National Wildlife Range and three basins in the interior of Alaska.

As a basis for establishing the proved reserves, potential resources, and gas deliverability for the Mackenzie Delta area, we have reviewed the various testimony, exhibits, and briefs filed in these proceedings and the initial decision of the Presiding Judge. 2/ We have also reviewed information recently submitted to the Canadian National Energy Board (NEB). Each of those recent gas supply submissions before the NEB of which we take official notice are fully identified in Appendix III-A.

B. Geology of the North Slope

A description of the geology of the area will no doubt aid in understanding and evaluating the hydrocarbon potential of the North Slope. The major geological elements which control the hydrocarbon potential of the Alaska North Slope consist of four structural features and two depositional cycles. The structural features are the Brooks Range uplift, the disturbed belt in the Brooks Range foothills, the deep Colville Geosyncline, and a broad northern regional high including the Barrow-Arch and the Prudhoe Bay structure.

2/ In arriving at our conclusions on supply, we have relied principally on information in the record of hearing before Judge Litt. The information was presented through testimony by experts from industry, consulting firms with expertise in this field, the State of Alaska, the FPC staff, and other Federal agencies. Additional data was also included in the record "by reference." Information from several sources not included in the record of these proceedings was also relied upon in the preparation of this report. These sources are identified in the text and are listed separately in Appendix III-B.

The first depositional cycle commenced during the Silurian or Devonian period and continued to the Jurassic period. The second depositional cycle commenced during Late Jurassic-Early Cretaceous period. 3/

From the Silurian-Devonian time to Jurassic time, a large geological basin existed in North Alaska and extended over the site of the present Brooks Range and into central Alaska. The northern shoreline of this basin oscillated from roughly the present location of the Brooks Range to roughly the present location of the Arctic Coast. During this depositional cycle, the source of sediments that filled the basin was from the north. Early Jurassic to Cretaceous uplifting, thrusting, and igneous activity disturbed this area and formed what are now referred to as the Brooks Range uplift on the south, the Beaufort uplift on the north, and the Colville Geosyncline between the uplifts. Subsequent erosion of the uplifted Brooks Range provided the sediments which filled the subsiding Colville Geosyncline. The total thickness of sediments at the deepest part of the Colville Geosyncline is estimated at 30,000 feet. 4/

C. Prudhoe Bay Field

1. Introduction

Several localized geological features are believed responsible for the Prudhoe Bay Field. The main producing formation in the Prudhoe Bay Field is the Sadlerochit Sandstone.

3/ Ref: Testimony and exhibits in FPC proceedings especially by Alcan witnesses Dr. Lowell and Newman. See also, National Petroleum Council (NPC), Future Petroleum Provinces of the United States, July, 1970, pp. 19-22. USGS Bulletin 815, Smith and Mertie, Geology and Mineral Resources of Northwestern Alaska, 1930, pp. 266-73.

4/ See Exhibit III-2.

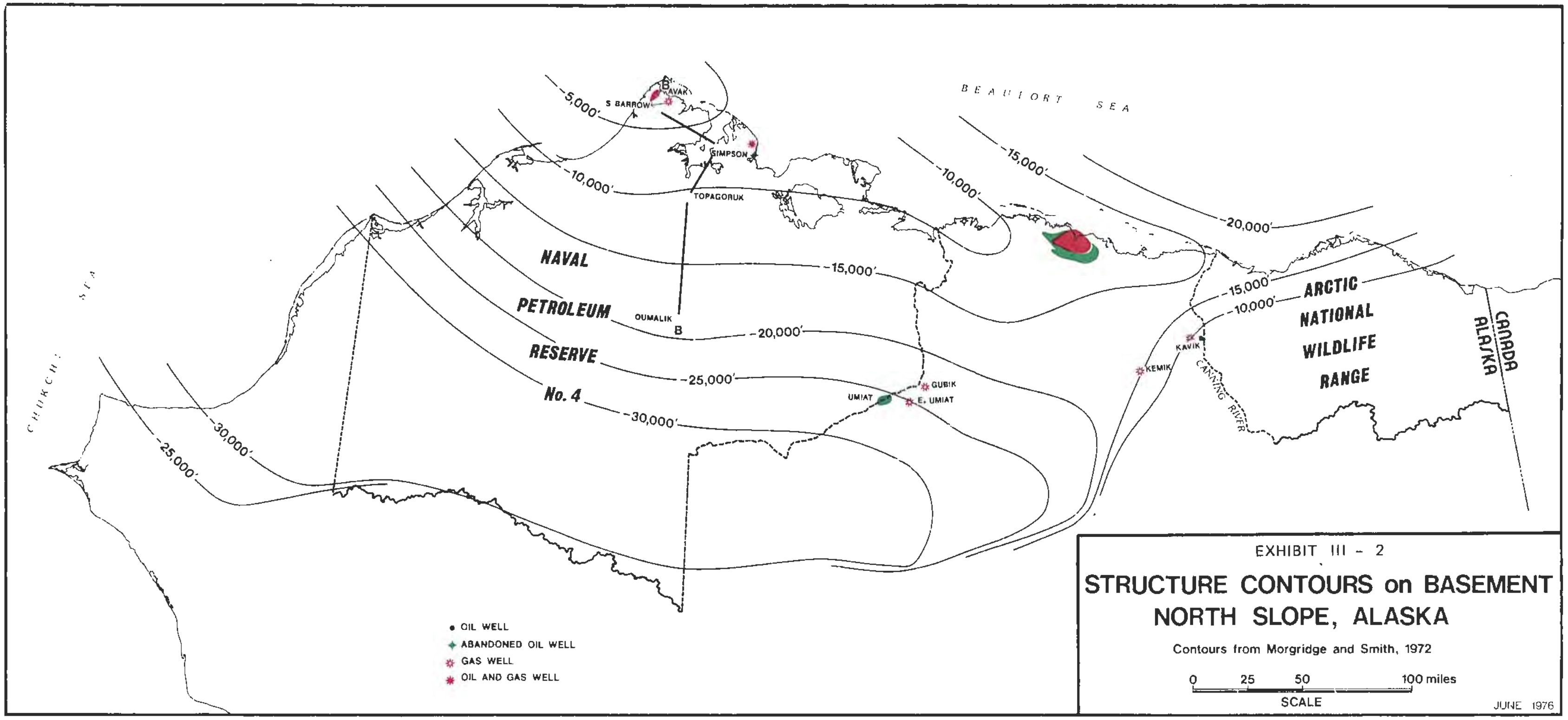

EXHIBIT III - 2

STRUCTURE CONTOURS on BASEMENT
NORTH SLOPE, ALASKA

Contours from Morgridge and Smith, 1972

Ref: Alcan Pipeline Company Application, Exhibit H-3; Witness Dr. James H. Lowell (Redrawn).

This formation is of Permian-Triassic age, and the source of sediments for this formation is believed to have been from the north. The general degradation in porosity and permeability within the Sadlerochit formation southward from the Prudhoe Bay Field is attributed to the derivation of sediments from a northern source. Near the present day eastern shoreline of the North Slope, the Sadlerochit and adjacent formations were deposited over the northern regional high. Subsequent uplifting of the northern area apparently created what is now described as a westerly plunging anticline. Later, erosion of the anticline truncated and exposed the Sadlerochit and adjacent formations. The truncated anticline was then overlain with thick layers of shale during the Cretaceous Period. The organically rich Cretaceous Shales are thought to be the original source of the hydrocarbons now trapped in the Prudhoe Bay petroleum reservoirs.

The combination of porous reservoir rocks in direct contact with the organically rich Cretaceous shales apparently is responsible for the vast petroleum accumulations in the Prudhoe Bay Field.

Before discovery of the Prudhoe Bay Field, the search for oil and gas on the North Slope was directed at the shallower Cretaceous formations. 5/ The knowledge of the combination of features existing at Prudhoe Bay and projection of this possible combination of geological features into adjacent areas forms the basis for some of the expected future additional gas potential for the North Slope. The most likely places where another Prudhoe Bay type of field may be found are north and west from Prudhoe Bay in the Beaufort Sea and east from Prudhoe Bay under the Arctic National Wildlife Range.

The Prudhoe Bay Field was discovered in 1968 when Atlantic Richfield Company and Exxon Corporation, U.S.A., drilled a jointly owned well. This field contains the largest accumulation of oil and gas ever discovered on the North American Continent.

5/ See discussion under NPR-4, Section D.

The State of Alaska owns the lands under which the Prudhoe Bay Field is located. Alaska has leased the lands for mineral exploration and production purposes to several oil and gas companies. Alaska has retained a 1/8 royalty interest in all of the tracts. 6/ The State has the option of either receiving payment for its 1/8 interest in the products sold or to retain 1/8 of the saleable products for its own use.

The principal leaseholders in the tracts under which the Prudhoe Bay Field is located are Sohio Petroleum Company, Atlantic Richfield Company, and Exxon Corporation. Other producers holding lesser portions of ownership in the Prudhoe Bay Field include Amerada Hess Corporation, Getty Oil Corporation, Hunt Industries, Caroline Hunt Trust Estate, Lamar Hunt Trust Estate, William Herbert Hunt Trust Estate, Louisiana Land and Exploration Company, Marathon Oil Company, Mobil Oil Corporation, Phillips Petroleum Company, Placid Oil Company, and Standard Oil Company of California. Additionally, BP Alaska, Inc. owns an overriding royalty interest in Sohio Petroleum Company's interest equal to 75 percent of all net profits from production above a certain level of oil production. 7/

The State of Alaska, through its Oil and Gas Conservation Committee of the Department of Natural Resources, will require that the Prudhoe Bay Field be operated to provide for the greatest recovery of oil and gas from the reservoirs and to protect the correlative rights of all lessees. Prudhoe Bay

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6/ The State's royalty interest is reduced to 5 percent for the first ten years after discovery of a new field. However, production of the Prudhoe Bay Field will not commence until approximately ten years after its discovery.

7/ Ref: Prudhoe Bay Unit Agreement submitted to State of Alaska on March 29, 1977.

Field operators were advised in late 1969 by the Oil and Gas Conservation Committee that it believed the reservoir characteristics of the field were such that combined operation of the leases as a single unit, i.e., unitization, would be necessary. On October 20, 1976, the producers submitted to the State of Alaska a proposed Unit Agreement and a proposed field operating plant for unitized production. 8/ A Final Unit Agreement and supporting documents were submitted to the State of Alaska on March 29, 1977. Hearings on the proposed unit agreement and field operating plan will be held by the appropriate State of Alaska authorities in early May, 1977.

Five petroleum reservoirs are found in the Prudhoe Bay Field. The following nomenclature to identify them has been used in the various testimony, exhibits, and other documents presented before the FPC and in most other data relating to the Prudhoe Bay area:

Kuparuk River Oil Pool

Prudhoe Bay Oil Pool
- Sag River Reservoir
- Shublick Reservoir
- Sadlerochit Reservoir

Lisburne Oil Pool

The area of the petroleum reservoirs in the Prudhoe Bay Field is determined by an unconformity (an impermeable shale deposit over-laying the truncated porous reservoir rocks) on the east, major faulting on the north and southwest, and an aquifer (water reservoir) on the northwest and south (see Exhibit III-3).

A geologic description of the various formations in the Prudhoe Bay Field is shown in Exhibit III-4. Descriptive reservoir data are listed in Exhibit III-5. The proposed development drilling program for the field is shown in Exhibit III-6.

8/ See pp. III-17 to III-20 for discussion of proposed field operating plan.

Ref: See Exhibit III-5 reference.

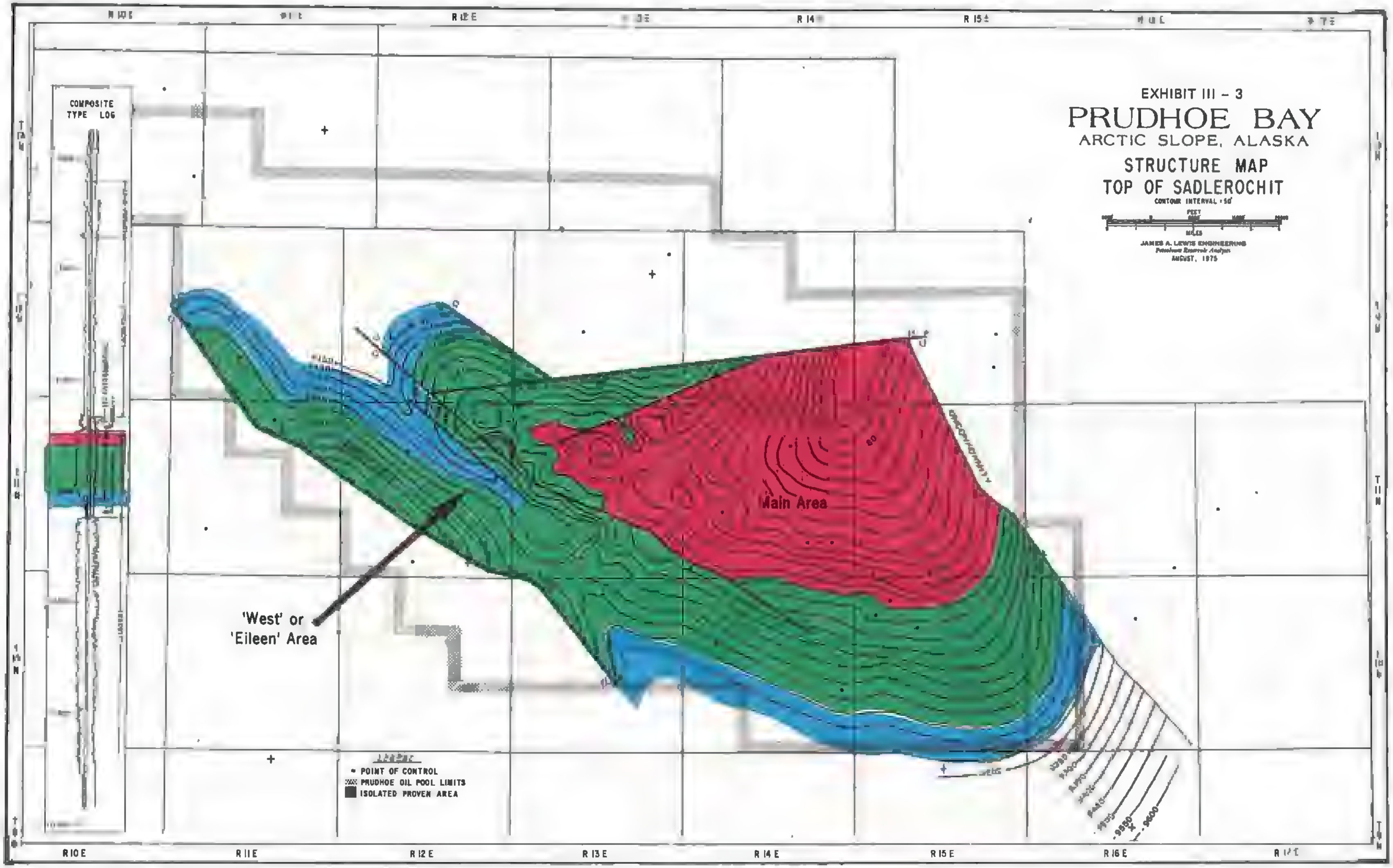

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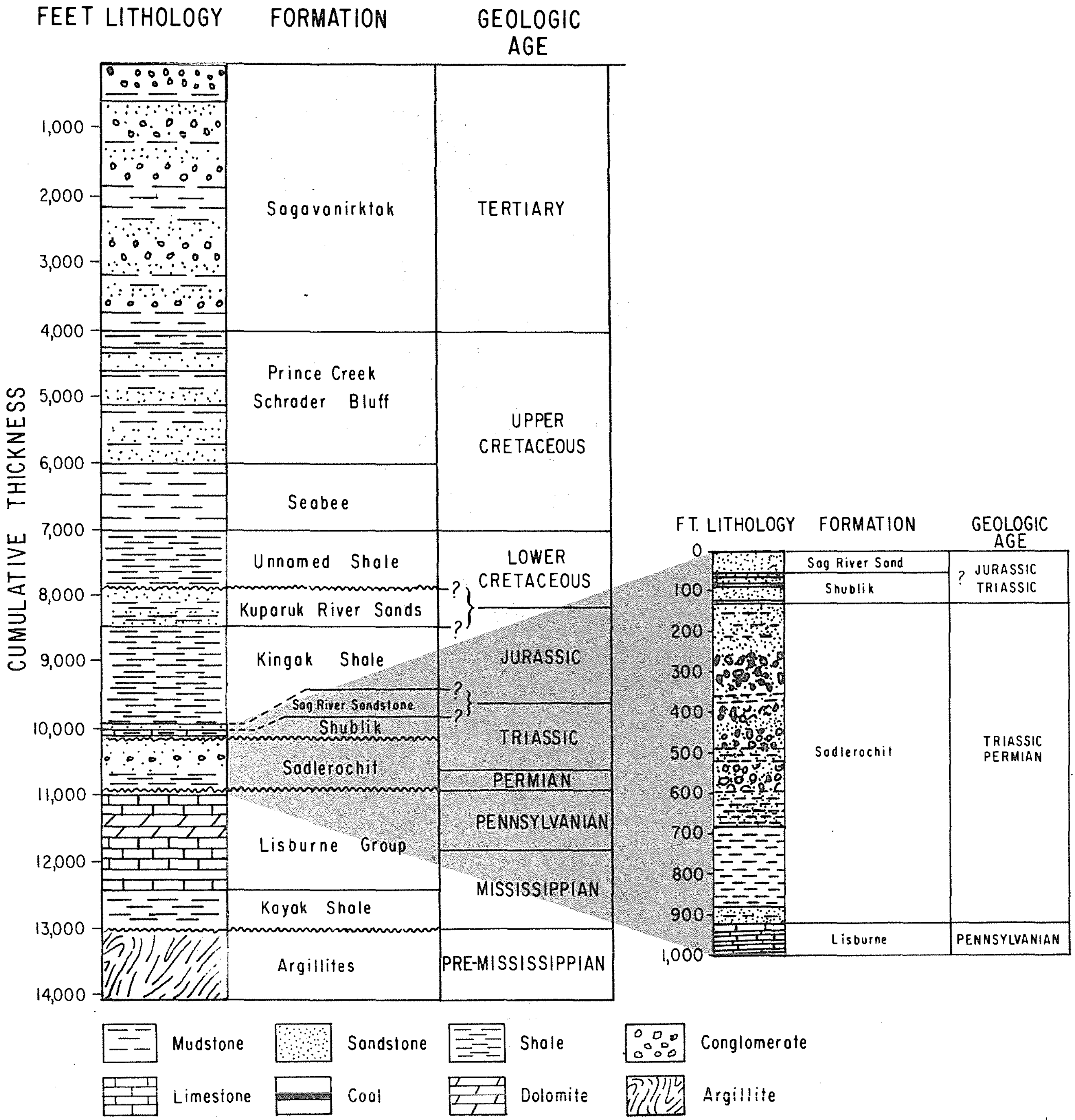
EXHIBIT III - 4

GENERALIZED STRATIGRAPHIC COLUMN

PRUDHOE BAY
ARCTIC SLOPE, ALASKA

JAMES A LEWIS ENGINEERING
Petroleum Reservoir Analysts
AUGUST, 1975



Ref: See Exhibit III-5 reference.

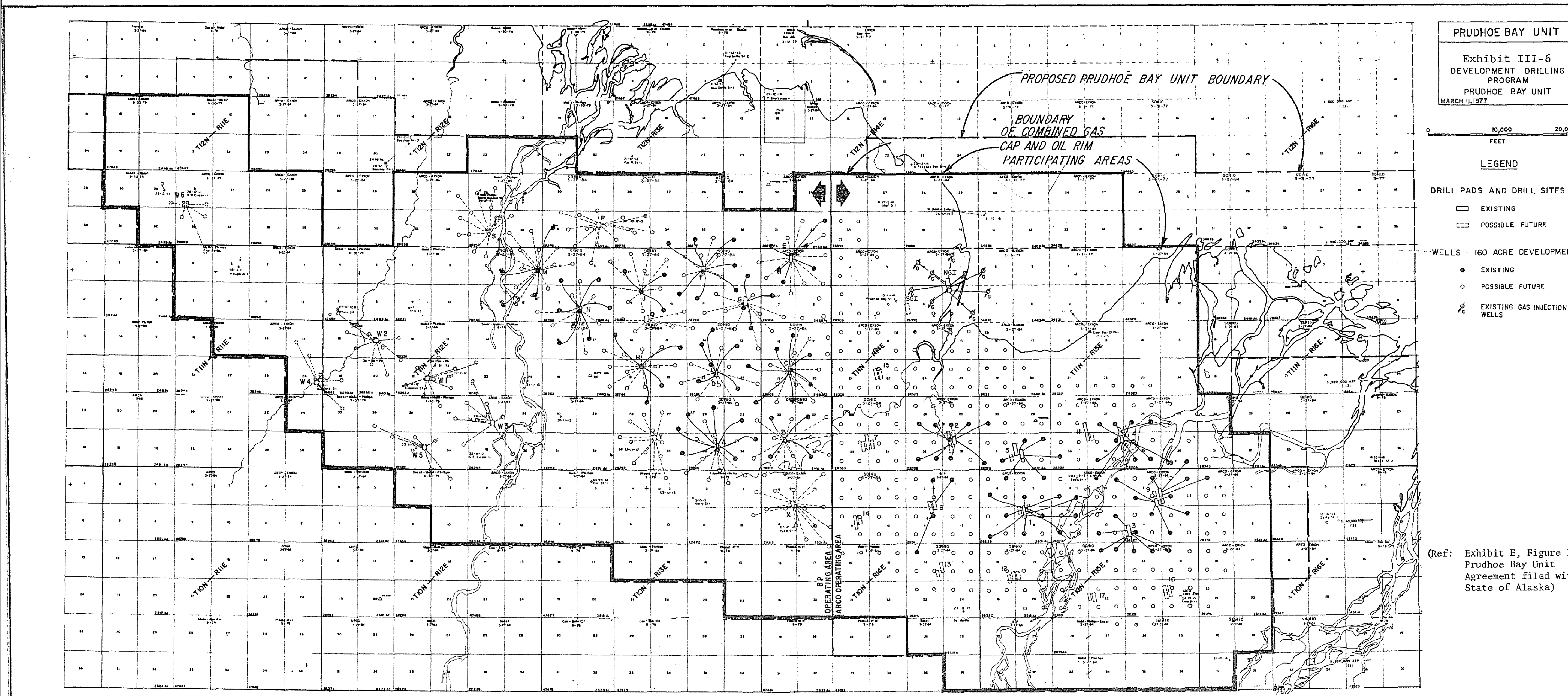
EXHIBIT III-5
PRUDHOE BAY FIELD
Descriptive Reservoir Data

	PRINCIPAL PROVEN AREA		ISOLATED PROVEN AREAS				
	PRUDHOE OIL POOL		PRUDHOE OIL POOL			Lisburne	Kuparuk River
	Sag River	Sadlerochit	Sag River	Shublik	Sadlerochit	Oil Pool	Oil Pool
Approximate Depth - Feet	8,200	8,400	-	8,300	-	9,500	6,700
Gas-Oil Contact, Average Subsea Depth	8,550±	8,590±	-	-	-	-	-
Oil-Water Contact, Average Subsea Depth	8,850±	9,000±	-	-	-	-	-
GAS CAP							
Average Net Pay Thickness - Feet	34.6	172.3	57	-	-	10	89
Weighted Average Porosity - %	20.98	22.14	20.98	-	-	11.04	20.32
Average Permeability - md.	140	250	140	-	-	-	-
Weighted Average Water Saturation - %	35.15	19.44	35.15	-	-	58.38	51.55
Average Subsea Datum Elevation - Feet	8,200	8,270	-	-	-	-	-
Initial Static Reservoir Pressure @ Datum - psig	4,260	4,270	4,260	-	-	4,700	3,400
Gas Gravity (Air = 1.0)	0.849	0.849	0.849	-	-	0.85	0.7(E)
Reservoir Temperature @ Datum - ^{o}F.	185	187	185	-	-	220	155(E)
Initial Deviation Factor	0.903	0.904	0.903	-	-	0.925	0.830
Initial Gas F.V.F. - CF/Scf	.003854	.003863	.003854	-	-	.003786	.004247
Initial Condensate Ratio - Bbls./MMscf of Reservoir Gas	34.8	34.8	34.8	-	-	34.8(E)	15(E)
Average Condensate Ratio - Bbls./MMscf of Reservoir Gas	17.1	17.1	17.1	-	-	17.1(E)	10(E)
OIL COLUMN							
Average Net Pay Thickness - Feet	16.6	195.1	45	53.5	72.3	172	47.5
Weighted Average Porosity - %	19.47	20.82	19.47	14.52	20.82	11.04	20.86
Average Permeability - md.	60	220	60	-	220	-	-
Weighted Average Water Saturation - %	41.88	36.23	41.88	43.33	36.23	58.38	53.38
Average Subsea Datum Elevation - Feet	8,700	8,000	-	-	-	-	-
Initial Static Reservoir Pressure @ Datum - psig	4,350	4,385	4,350	4,370	4,385	4,700(E)	3,400
Saturation Pressure @ Datum - psig	4,350	4,385	4,350	-	4,385	-	-
Reservoir Temperature @ Datum ^{o}F	197	200	197	199	200	220(E)	155(E)
Oil F.V.F. @ Initial Pressure - RB/STB	1.41	1.38	1.41	1.38	1.38	1.65(E)	1.19
Oil F.V.F. @ Saturation Pressure - RB/STB	1.41	1.38	1.41	-	1.38	-	-
Initial Solution Gas-Oil Ratio - Scf/STB	800	750	800	750	750	1,145	285
API Gravity - Degrees	39.0	26.8	39.0	27.2	26.8	26.9	25.1

(E) = Estimated.

Ref: "Study of Reserves, Hydrocarbons-In-Place, Production Rates and Present and Projected Capacities, December 31, 1974, Prudhoe Bay Field, North Slope, Alaska;" Prepared for FEA by James A. Lewis Engineering, Dallas, Texas (Exhibit 9).

Note: Because this report was based upon information available during the initial development of the Prudhoe Bay Field, some of the above listed data may not be in total agreement with current data. However, any differences are not believed to be large. These data are presented only for informative purposes.



(Ref: Exhibit E, Figure 1, Prudhoe Bay Unit Agreement filed with State of Alaska)

At present, active development is occurring in only the Prudhoe Bay Oil Pool within the Prudhoe Bay Oil Field. The Sadlerochit Reservoir contains approximately 85 percent of the gas cap in-place hydrocarbons and approximately 97 percent of the oil zone in-place hydrocarbons. 9/

2. In-Place Gas Volumes

Estimates of the volume of original gas in-place in the Prudhoe Bay Oil Pool range from earlier estimates of 35.1 Tcf to later estimates of approximately 42.8 Tcf. Much of the difference in these estimates can be attributed to a larger than originally anticipated gas cap. The increase in estimated gas-cap size is due in substantial part to the now generally held belief that the Sadlerochit formation (the main producing formation) may be in pressure communication with the Shublick and Sag River formations as a result of possible vertical fractures. However, actual field performance data will be required to verify the presence and extent of pressure communication.

Gas supply studies presented by El Paso, the Department of the Interior, and the original study presented by the State of Alaska utilized an in-place gas volume of 35.1 Tcf. The Department of the Interior (DOI) also included 6.8 Tcf of expected reserves additions by 1985 from the Sadlerochit formation. 10/ The State of Alaska later submitted a study

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9/ Ref: Exhibit ALA-33; "Technical Considerations, Prudhoe Bay Unit Operating Plan, North Slope-Alaska"; Figure 3.

10/ Actually, DOI discounted the probable reserves additions by 30 percent and discounted the possible reserves additions by 70 percent.

projecting 40.4 Tcf. 11/ Arctic gas sponsored a study which estimated 39.0 Tcf of in-place gas, including 3.1 Tcf in the Sag River formation. Alcan presented a gas supply and deliverability study predicated upon an in-place gas volume of 41.9 Tcf. The major interest leaseholders' proposed field operating plan is predicated upon an in-place gas volume of approximately 42.8 Tcf. 12/

3. Gas Shrinkage and Field Usage

All of the gas physically recovered from the Prudhoe Bay Field will not be available for sale. For example, Alcan utilized a shrinkage factor of 17 percent to account for removal of CO_2 and liquids and for fuel to be used in field operations. El Paso employed a shrinkage factor of 20 percent to account for removal of carbon dioxide and liquids, and fuel utilized in processing. (8/1392). However, the Alcan shrinkage factor does not allow for gas processing and the El Paso factor does not allow for field use of gas. Based upon all available information, we believe the portion of produced gas that will not be available for sale (shrinkage factor) to be approximately 26 percent. 13/ This "shrinkage factor" allows for volume reductions of 12 percent for CO_2 removal, 8 percent for field use, 14/ and 6 percent for conditioning gas for transportation.

11/ Ref: Exhibit ALA-4.

12/ Ref: Exhibit ALA-33; Fig. 3 and p. 16. [(29.3 MMMRB ÷ 1.36 RB/STB) x (750 SCF/STB)].

13/ See for example: T. 19,466; 19,470; 19,494-496; 19,498-499; Exhibit ALA-4.

14/ This factor does not include fuel required to reinject gas which is produced but not sold. Fuel required for gas reinjection is estimated at 4 percent (Ref: Exhibit ALA-33, p. 25).

The actual amount of gas required as fuel for field operations will vary over the producing life of the field and will depend on the operations being conducted at various times. For example, some added amounts of gas will be required as fuel for artificial oil lifting operations after the initial stages of oil production. Additionally, fuel will be required to operate water injection facilities, if and when a major source water injection program is initiated. However, increased fuel requirements do not mean necessarily that less gas will be available for sale, because the producing gas/oil ratio will most likely increase with time. Any added fuel requirements for artificial lift and water injection should be more than offset by the increased amount of hydrocarbons recovered from the reservoir.

The 6 percent volume reduction is attributable to conditioning the gas for shipment. This process involves removal of CO_2, removal of liquefiable hydrocarbons as required for dew point control, and compression and cooling of the gas to pipeline pressure and temperature specifications. The exact degree of dew point control, compression, and cooling will, of course, depend on the final design of a gas transportation system.

4. Deliverability

Several methods were employed by the applicants and others to estimate the permissible Prudhoe Bay Field gas deliverability. Because most Prudhoe Bay Field gas reserves are in the Sadlerochit Reservoir, most of the deliverability studies focused on this reservoir. The most widely used method for studying the Sadlerochit Reservoir involved computerized three-fluid phase, two-dimensional cross-section numerical simulation models of the Sadlerochit Reservoir. The models attempted to simulate the effects on reservoir performance of rock properties, reservoir fluid properties, forces controlling fluid movement and various reservoir management programs. Many field operating variables were introduced, such as rate of oil production, rate and timing of gas sales, well spacing, reservoir perforation exposure, position of perforations relative to gas/oil and water/oil interfaces, maximum allowable producing gas/oil ratios and water/oil ratios for individual wells before recompletion in another interval or abandonment, amount of produced gas reinjected, amount and timing of water injection, and others.

It should be noted that (a) ultimate oil recovery could be significantly affected by the timing and amount of gas sales, (b) ultimate gas recovery will not be significantly affected by the timing and rate of gas sales, and (c) water injection programs, well completion design, and other reservoir management techniques can be employed which will permit relatively early gas sales and also result in optimum oil and gas recoveries. Most studies indicate that gas sales of at least 2.0 Bcfd can be made without having a detrimental effect on the ultimate recovery of oil or gas from the Prudhoe Oil Pool.

The producing mechanisms available in the reservoir are depletion drive in the oil zone, gas cap expansion, gravity drainage, and water drive. The primary producing mechanisms will most likely be gravity drainage and depletion drive with gas cap expansion. A strong, efficient natural water drive may not occur because of (a) the general degradation in the Sadlerochit porosity and permeability away from the Prudhoe Bay Field, 15/ (b) the presence of a heavy oil or tar layer at the base of the oil column throughout much of the field, and (c) the fact that all of the perimeter of the oil column is not in contact with the aquifer (see Exhibit III-3).

15/ The general southward degradation of the Sadlerochit rock properties is attributed to a northern sediment source during the deposition of the Sadlerochit.

Without a strong natural water drive and/or an extraneous source water injection program, the rate at which gas is produced and sold will determine the depletion rate of reservoir energy needed to produce the oil. Additionally, if the pressure in the gas cap is reduced below the pressure in the oil zone, there is good likelihood that oil will migrate from the oil zone into the gas cap and further reduce oil recoveries. The gas produced during at least the early years of oil production can be advantageously utilized for reinjection in order to maintain reservoir pressure and thus sustain oil production. The gas should, therefore, not be viewed as a by-product which has to be sold, or that should even necessarily be sold during the initial years of oil production. 16/

Briefly stated, the producers' proposed operating plan for the Prudhoe Bay Field which is now under review by the State of Alaska's Department of Natural Resources provides for the following:

Short-Term Operating Plans

1. Commence oil producing in mid-1977 at rate of 600,000 barrels per day (BO/D). Increase oil production to 1.2 million BO/D, assuming available pipeline capacity.

2. Reinject produced gas, less amount needed for local fuel, into gas cap until gas pipeline and

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16/ However, the producers have submitted a proposed field operating plan to the State of Alaska, which would employ reservoir management techniques permitting gas sales without adversely affecting oil recovering efficiency. See below.

gas conditioning plant are approved and constructed (currently estimated by producers to be about 5 years after start of oil production). 17/

3. Gas pipeline deliveries of 2.0 Bcfd to commence as soon as gas pipeline and gas conditioning plant are approved and constructed.

Long-Term Operating Plans

1. Complete field facilities during 1978-1979 for sustained oil production rate of 1.5 to 1.6 million BO/D. Increase production to 1.5 to 1.6 million BO/D when oil pipeline capacity is available. Maintain 1.5 to 1.6 million BO/D rate for approximately 8 years by additional development drilling. Have total of about 500 wells on 160-acre spacing located where the oil column is at least 100 feet thick. Further drilling in some areas may occur between the planned 160-acre well spacing.

2. The planned initial gas pipeline deliveries of 2.0 Bcfd "is a conservative volume which can clearly be supported by the reservoir and gas pipeline deliveries of up to 2.5 Bcfd may be justified, depending upon field performance data and availability of pipeline capacity." 18/

17/ Rapid gas cap expansion during the initial years of oil production should eliminate oil migration into the gas cap once gas sales commence. Therefore, gas reinjection during the initial years of oil production is very beneficial. Gas would probably not be available for sale earlier than four to five years after the start of oil production.

18/ Exhibit ALA-33, pp. 5-6.

Water Injection Plans

1. Inject produced water initially into shallow Cretaceous sands. When water production becomes significant, selectively inject into areas of the producing reservoir which experience low primary oil recovery. Produced water rates could be as high as 500,000 barrels per day.

2. Supplement injection of produced water with injection of extraneous source water "when addition recovery predictions of 3% to 7% of the original oil in place from such operation are verified and over $1 billion added costs economically justified." 19/

The producers estimate that the ultimate oil and gas recoveries from the Main Area Sadlerochit reservoir, 20/ based upon an assumed maximum oil production rate of 1.5 million barrels per day (MMB/D) and gas pipeline deliveries of 2.0 billion cubic feet per day (BCF/D) commencing 4-1/2 to 5 years after the start of oil production, will be as follows:

(1) Natural recovery mechanisms (without the injection of produced water) should result in recovery of from 32% to 35% of the original oil in place (OOIP). This oil recovery should be achieved over a period of 25 to 30 years. Ultimate gas recovery should range from 75% to 80% of the original gas in place (OGIP), and will be recovered in approximately 35 years.

19/ Ibid., p. 6.

20/ The field is divided into what is referred to as "The Main Area" and the "Eileen Area" (see Exhibit III-3). The Main Area Sadlerochit reservoir contains approximately 84 percent to 93 percent of the total field's gas cap and oil zone hydrocarbons, respectively.

(2) Selective injection of produced water into the Sadlerochit reservoir may increase the oil recoveries to 33% to 36% of OOIP.

(3) A properly designed source water injection program, implemented within about 5 to 9 years after the start of oil production, could increase the ultimate oil recovery to 39% to 40% of OOIP. The ultimate oil recovery is not sensitive to the timing of source water injection in the 5 to 9 year period. 21/

The producers' technical report also states:

(4) Oil production rates in the range of 1.2 to 1.8 MMB/D have no significant effect on the ultimate recovery of oil or gas.

(5) The timing of the commencement of 2.0 BCF/D of gas pipeline deliveries 'does not significantly affect ultimate oil recovery under sound reservoir management plans.' The minor potential reduction in ultimate oil recovery resulting from the commencement of 2.0 BCF/D of gas sales earlier then 8-1/2 to 10 years from the start of oil production can be offset by modifying one or more operating factors (e.g., number and location of wells, volume and location of water injection, etc.). 22/

The above opinions of the field operators, together with the various deliverability studies of the applicants and others, clearly demonstrate that it is reasonable to

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21/ The producers state that two or more years of production performance history and testing data will be required to design and determine the economic feasibility of a source water injection program. The producers estimate the cost of the source water injection program will be over $1 billion.

22/ Id., p. 30.

expect gas sales of at least 2.0 Bcfd from the Main Area Sadlerochit reservoir. The producers also state that studies have shown that the gas delivery rate can be increased to 2.5 Bcfd without affecting ultimate oil recovery if appropriate modifications are made to the reservoir management plan. The producers make the qualifying statement, however, that the "studies were conducted without economic analysis, and justification for gas sales above 2.0 Bcfd will depend upon actual production performance and economic considerations." 23/

The projected 2.0 Bcfd to 2.5 Bcfd deliverability is based upon the productive capacity of only the Main Area Sadlerochit reservoir. Additional gas should also be available from the Sadlerochit formation in the Eileen Area and possibly from the Sag River and Shublick reservoirs in the Prudhoe Bay Oil Pool. Additional amounts of gas may also be available from the Kuparuk River Oil Pool and the Lisburne Oil Pool. However, reserves and deliverability from the Eileen Area and the Kuparuk River and Lisburne Oil Pools will be small compared to the Main Area Sadlerochit reservoir.

In summary, all of the information available at this time indicates that the gas volumes available to any of the proposed gas transportation systems from the Prudhoe Bay Field should be at least 2.0 Bcfd and possibly slightly more than 2.5 Bcfd, beginning four to five years after commencement of oil production and continuing for 25-35 years.

23/ *Ibid.*, p. 31.

5. Kuparuk River Oil Pool and Lisburne Oil Pool

The Prudhoe Bay Field contains, in addition to the Prudhoe Bay Oil Pool, the shallower Kuparuk River Oil Pool and the deeper Lisburne Oil Pool. The Kuparuk River Oil Pool is composed of one reservoir, the Kuparuk River Sandstone. The Lisburne Oil Pool is composed of one reservoir, the Lisburne Limestone. These reservoirs have not been developed extensively and little information is available on them.

The DOI Report to Congress 24/ included the following expected additions to proved reserves by 1985 from the Kuparuk River and Lisburne Oil Pools:

	Probable Reserves	Possible Reserves
Kuparuk River	2.1 Tcf	3.3 Tcf
Lisburne	1.8	3.8
	3.9	7.1
"Discount" Factor 25/	70%	30%
Expected Reserves by 1985	2.7 Tcf	2.2 Tcf

A recent report prepared for FEA 26/ estimates the "speculative" reserves for the Kuparuk River and Lisburne Oil Pools as follows:

24/ See p. III-34, n.44 for description of report.

25/ Discount factors used by DOI.

26/ Report entitled "The Determination of Equitable Pricing Levels for North Slope Alaskan Crude Oil," November, 1976; prepared for FEA by Mortada International, Dallas, Texas. This report was not included in the record of these proceedings; however, official notice is taken of the report for use as comparison with DOI's estimated reserves additions. Note: The speculative gas reserves were computed from the speculative oil reserves and the gas-oil ratios cited in the report.

Kuparuk River	0.1 to 0.5 Tcf
Lisburne	0.2 to 0.9 Tcf
Total	0.3 to 1.4 Tcf

The above comparison suggests that potential gas supplies which may be realized from the Kuparuk River and Lisburne reservoirs is still highly uncertain. The upper range of estimated gas deliverability from the Prudhoe Bay Field includes the possible availability of some gas from the Kuparuk River Oil Pool and the Lisburne Oil Pool.

6. Summary and Conclusions

The Prudhoe Bay Field contains the largest accumulation of oil and gas ever discovered on the North American Continent. The in-place gas volumes in the field is in excess of 40 Tcf. 27/ Estimates of the portion of the in-place gas that can be ultimately recovered range up to 75-80 percent. Gas can be made available for sale from the Prudhoe Bay Field at a rate of at least 2.0 Bcfd and possibly slightly more than 2.5 Bcfd.

The Prudhoe Bay Field is an oil reservoir. The primary producing mechanisms will be gravity drainage and depletion drive with gas cap expansion. A strong efficient natural water drive may not occur. If pressure in the gas cap is reduced below the pressure in the oil zone, it is likely that oil will migrate from the oil zone into the gas cap and thus reduce oil recoveries. Therefore, gas produced during at least the early years of oil production can be very advantageously utilized for reinjection in order to maintain reservoir pressure and thus sustain oil production. The gas should not be viewed as a by-product that has to be sold, or that should even necessarily be sold during the initial years of oil production.

27/ Based upon the most recent estimates.

In order to attain a gas sales rate in excess of 2.0 Bcfd - or perhaps even to sustain a 2.0 Bcfd sales rate over a prolonged period of time without adversely affecting the reservoir - a source water injection program and/or other reservoir management techniques will be required. The producers indicate that two or more years of field production performance history and testing data will be required to design and determine the economic feasibility of a source water injection program. Reinjection of produced gas will require approximately 4 percent usage as fuel for compression. Therefore, the longer gas sales are postponed, the less total gas will be available for sale.

The evidence presented before the FPC in these proceedings indicates it is reasonable to expect that gas can be made available from the Prudhoe Bay Field to any of the proposed gas transportation systems at a rate of at least 2.0 Bcfd and possibly 2.5 Bcfd, or even slightly higher. Gas deliveries can be sustained for 25 to 35 years, depending on the sales rate and ultimate gas recovery efficiency, and assuming gas sales commence within roughly four to five years after oil production commences. By employing proper reservoir management techniques, this level of sales can be achieved without having a detrimental effect on the portion of in-place hydrocarbons ultimately recovered.

D. Naval Petroleum Reserve No. 4

1. Introduction

Naval Petroleum Reserve No. 4 (NPR-4) 28/ is located in the Northwestern portion of the North Slope of Alaska. The Eastern boundary is about 60 miles from Prudhoe Bay. It occupies an area of 37,000 square miles (approximately the size of the State of Indiana). This area was established as a naval petroleum reserve in 1923. Since then, several exploration programs have been conducted to assess the petroleum (and other minerals) resource potential of the area. 29/ These exploration programs have tended to diminish expectations of petroleum potential in NPR-4.

The record in these proceedings cites current and past estimates of potential gas supplies for NPR-4 ranging from a low of 5 Tcf to a high of 78.65 Tcf. The most current detailed analysis of the NPR-4 gas potential available to the FPC estimates approximately 14 Tcf of undiscovered, recoverable natural gas in NPR-4. This figure is contained in a report prepared for the Federal Energy Administration

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28/ NPR-4 will be renamed the National Petroleum Reserve - Alaska (NPR-A) upon transfer to the U. S. Department of the Interior on June 1, 1977, pursuant to P.L. 94-258 ("National Petroleum Reserve in Alaska," 42 U.S.C. 6501, *et seq*.).

29/ Some surface exploration of NPR-4 may have occurred prior to 1923, but the nature and results of any such activities are not well documented.

by Resource Planning Associates. 30/ This report was not contained in the record of these proceedings. However, because the report reflects the results of recent exploration activities in NPR-4, we have taken its information into account. The report will hereinafter be referred to as the "FEA Report on NPR-4."

No gas is currently available in sufficient quantities in NPR-4 for attachment to any of the proposed Alaska gas transportation systems. Based upon all information available to the FPC at this time, it is not realistic to expect that any significant amount of economically producible gas would be available from NPR-4 during at least the early years of operations of any of the proposed gas transportation systems. Furthermore, the only activity currently authorized by Congress for NPR-4 is the on-going seven-year exploration program (FY 1974-FY 1980), described more fully below. No development or production of any oil and gas discoveries is authorized.

The known oil and gas deposits in NPR-4 are scattered, small in size, and do not follow any definitive "productive trends" (i.e., any grouping of fields, trends or lines of fields). Therefore, no substantial weight should be given to the limited amount of gas known to exist on NPR-4 and the future possible gas supplies from NPR-4 in comparing the proposed gas transportation systems at this time. The only purpose of preparing the projected gas availability

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30/ Federal Energy Administration (FEA). "The Exploration, Development, and Production of Naval Petroleum Reserve No. 4"; prepared for FEA under Contract No. CR-05-60579-10 by Resource Planning Associates, Cambridge, Mass., July 19, 1976. The report, together with an executive summary of the report as constructed by FEA, was submitted by the Administrator of FEA, in cooperation and consultation with the Secretary of the Navy and the Secretary of the Interior, to the Committees on Interior and Insular Affairs of the Senate and the House of Representatives in fulfillment of the requirement of Section 164 of the Energy Policy and Conservation Act, as amended by Section 105(a) of the Naval Petroleum Reserves Production Act of 1976.

schedule for NPR-4 is to develop the range of possible future gas supplies that may be available from the North Slope which may influence the weight given to system expansibility in evaluating the proposed gas transportation systems.

2. History of Exploration

In response to the heavy demand that World War II placed upon our petroleum reserves, the U. S. Navy initiated an exploration program of NPR-4 and the adjacent areas in 1944. Exploration of NPR-4 continued through 1953 and resulted in the following petroleum discoveries: 31/

Field	Reserves
Oil - Umiat	72-100 Million Barrels
Simpson	12 Million Barrels
Gas - Barrow	5-9 Billion Cubic Feet
Gubik	300 Billion Cubic Feet

Additionally, prospective gas fields were found at Meade, Square Lake, Oumalik, and Wolf Creek, and a small amount of oil was encountered at Fish Creek. 32/

The only drilling activity on NPR-4 between 1953 and 1974 was in the South Barrow Gas Field (five miles east of the City of Barrow). Wells were drilled in this field to provide fuel for heating and electric generation for the Barrow community with a population of approximately 2,300. None of the other above listed oil and gas fields discovered during the 1944-1953 exploration program are now considered

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31/ Office of Naval Petroleum and Oil Shale Reserves (NPOSR), "Annual Report of Operations", October 1, 1976, p. 36.

32/ Ibid.; also NPC, op. cit.; also T. 9,948.

capable of development on an economic basis. The cost of producing and transporting the petroleum products would exceed their expected sales value. 33/

As a result of the Arab oil embargo, exploration of NPR-4 was resumed in 1974 by the Navy at the direction of Congress. 34/ A seven-year exploration program is currently underway (FY 1974-FY 1980) which calls for drilling 26 test wells and 10,235 line-miles of seismic surveying. 35/ At the time of these proceedings, only two wells had been drilled. These wells are the Cape Halkett No. 1, located 100 miles ESE of Barrow, and the Iko Bay No. 1, located 22 miles ESE of Barrow. The Cape Halkett No. 1 well penetrated the same pre-cretaceous formations that are productive in the Prudhoe Bay Field. The Cape Halkett No. 1 well is classified as a dry hole. The Iko Bay No. 1 is described as a "marginal gas well." 36/ The purpose of drilling this well was to find additional gas to satisfy the projected gas demands of Barrow. 37/ The FEA Report on NPR-4 lists a third well drilled during the current seven-year explorative program. This well, Lake Teshekpuk No. 1, was drilled to basement rock at a depth of 10,664 feet and is located on the eastern shoreline of Lake Teshekpuk. Commercial quantities of oil or gas were not discovered at this well.

33/ FEA, *op. cit.*

34/ T. 11,971.

35/ T. 9,951; 11,971.

36/ T. 11,979; also FEA, *op. cit.*

37/ T. 9,949; also FEA, *op. cit.*

The FEA Report on NPR-4 summarizes the past North Slope exploration efforts as follows:

> "Prior to the NPR-4 exploratory program beginning in 1974, the hypothesis was that oil and gas would most likely be found in relatively shallow and geologically young Cretaceous sands. Even though no commercial accumulations were found, the discovery of oil in the Umiat and Simpson Fields seemed to bear out this hypothesis. However, these 'red herring' discoveries kept attention focused on the younger zones, rather than on the older, deeper sands later found to be productive at Prudhoe Bay. Industry, working from the results of the Navy 1944-53 program, began drilling wildcat wells into the Cretaceous zone south of Prudhoe Bay. At first, no commercial deposits were found. But the drilling proceeded northward, until Arco's Prudhoe Bay State No. 1 exploratory well was drilled into the deeper and geologically older sediments, and the Sadlerochit pool in the Triassic-Permian formation was discovered in 1968. . ."

Current drilling is limited to the northern portion of NPR-4 until the Environmental Impact Statement (EIS) for the remainder of NPR-4 is completed. The Final EIS for NPR-4 should be completed prior to the start of exploration activities in FY 1978. 38/ Deeper drilling on NPR-4 could result in additional oil and gas discoveries. However, based upon all currently available information, it is extremely unlikely that the combination of geological features responsible for the vast petroleum accumulations at the Prudhoe Bay Field could be encountered on NPR-4.

3. Petroleum Resource Assessments

Various gas resource estimates for NPR-4 are cited by the applicants and others in these proceedings. Arctic Gas refers to the Arctic Institute of North America (AINA)

38/ NPOSR, *op. cit.*, p. 41.

study conducted during 1969 for the Navy. The AINA study stated that the NPR-4 petroleum resource potential was 14.3 billion barrels of oil and 78.65 Tcf of gas. 39/ Arctic Gas also makes reference to a report estimating the speculative resources of oil and natural gas issued June 1974, by the Division of Geological and Geophysical Surveys (DGGS) of the State of Alaska. 40/ Based on Arctic Gas' review of the DGGS report and other data, Arctic Gas concluded that "it is reasonable, if not conservative, to estimate potential [undiscovered] reserves onshore North Slope of 41.8 Tcf". (Arctic Gas Br., p. 7.) Alcan, in its Gas Supply Reply Brief, states that all credible evidence shows that the AINA forecast is totally unrealistic, and Alcan is critical of the DGGS speculative resource estimate because it is based upon a "Basin Volumetric Approach." 41/ Alcan estimates that the undiscovered, recoverable gas reserves on the North Slope are in the range of 25 Tcf; 10.2 Tcf west of the Canning River, of which 5 to 6 Tcf are under NPR-4, and 14.5 Tcf under the Arctic National Wildlife Range. El Paso focused on the reserves in the Prudhoe Bay area and the Mackenzie Delta and did not present a separate resource estimate for NPR-4. The FPC Staff makes reference in its gas supply brief to the suggested potential of 14.3 Tcf in NPR-4 (T. 28,926-928). This latter estimate was based upon the then unreleased FEA Report on NPR-4, which is discussed in detail later.

39/ T. 11,973-974.

40/ Alaska Division of Geological and Geophysical Surveys, "Energy and Mineral Resources of Alaska and the Impact of Federal Land Policies on Their Availability", Alaska Open File Report 50, Klein, *et al*. (June, 1974).

41/ This method essentially requires an estimation of (a) the volume of sedimentary rocks in the basin under study, and (b) recovery factors expressed, for example, as billion cubic feet of gas per cubic mile of sedimentary rocks and million barrels of oil per cubic mile of sedimentary rocks based upon analogies with known petroleum productive basins. Multiplication of the basin volume (a) and the recovery factors (b) produces the resource estimate.

The USGS estimates that the potential gas resources for the entire onshore Alaska North Slope has a 95 percent probability of being at least 14 Tcf and a 5 percent probability of being 49 Tcf or more. The statistical mean is 28 Tcf. 42/ The FEA Report on NPR-4 (discussed immediately following) states that the USGS has recently made an informal estimate of 7 to 25 Tcf for the NPR-4 gas resources (i.e., 7 Tcf with a 95 percent probability and 25 Tcf with a 5 percent probability). The FEA Report on NPR-4 also states that "it is anticipated that USGS will release a new, formal estimate for NPR-4 resources sometime in 1976."

The most recent detailed analysis of the potential petroleum resources for NPR-4 available to the FPC at this time is the previously referred to FEA Report on NPR-4. This study has already been forwarded to Congress and will be only very briefly described here. The report states, in pertinent part, as follows:

> ". . . Although any estimate of NPR-4 prospects is uncertain because of the limited drilling to date, the most likely levels of undiscovered, recoverable resources in NPR-4 are estimated at 5 billion barrels of liquid hydrocarbons (oil and gas condensate) and 14.3 trillion cubic feet of gas. This estimate is highly uncertain since there is no known reliable technique that permits an estimate of undiscovered petroleum resources prior to exploratory drilling."

The resource estimate contained in this report is stated to be "based on information that is an order of magnitude better than previously available to either USGS or AINA." The report specifies that the new resource estimate is based on the inclusion of the following information:

42/ USGS: "Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States"; Circular 725 (1975), p. 33. (Item by Ref: AP-H).

a) Prospect and closure maps, prepared at the direction of the Navy, from the first 3,500 line miles of seismic data.

b) The well logs from all wells drilled in NPR-4 through the 1974-75 drilling season, including Cape Halkett No. 1 well logs.

c) The results of oil companies deep-exploration wells east of NPR-4 at the Colville River Delta and south of Prudhoe Bay.

d) Syntheses of geological studies carried out over the last 30 years.

With respect to the likelihood of finding large petroleum deposits on NPR-4, the FEA Report states:

> "Although numerous attractive hydrocarbons prospects exist within NPR-4, there is as yet no indication of massive geologic structures with reserve potential of the magnitude found at Prudhoe Bay."

Based upon all information available to the FPC at this time, we have concluded that the FEA Report on NPR-4 sets forth the most realistic assessment of the potential petroleum resources for NPR-4. The 14.3 Tcf assessment is, however, only an estimate of the potential resources available in NPR-4 and not a prediction that 14.3 Tcf of gas reserves can be economically developed and produced. All current information indicates that the portion of the NPR-4 resource potential capable of economic development and production - during at least the short term - will be relatively small because of the expected small size and scattered locations of the fields and the expected high costs of developing and producing the fields and transporting the products.

4. Projected Gas Availability Schedule

As stated before, the only purpose of a projected gas availability schedule for NPR-4 is to assess the possible degree of expansion that may be required in the future for the gas transportation system.

For purposes of projecting a gas availability schedule, the assumptions underlying the hypothetical development program employed in the FEA Report were adopted. They were:

a) No production during years 1 through 4.

b) 25 percent of peak production in year 5.

c) 75 percent of peak production in year 6.

d) Peak production in years 7 through 15.

e) Annual rate of decline of 25 percent after year 15.

It is not realistic to expect that all of the 14.3 Tcf potential gas resources would be capable of economic development and production during the timeframe of this inquiry. 43/ As a basis for illustrating a possible range of production values, separate projections were made for development and production of 15 percent, 30 percent, 50 percent and 70 percent of the potential resource. The

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43/ The Alaska Natural Gas Transportation Act of 1976 requires that FPC make various determination "for each year of the 20-year period which begins with the first year following the date of enactment" of such Act. It is within this time context that the gas availability schedule is estimated.

upper range of 70 percent and the intermediate range of 30 percent correspond to the factors used by the DOI 44/ in discounting probable and possible reserve additions, respectively, for the North Slope of Alaska and the Mackenzie Delta. The 70 percent factor is probably too optimistic. The maximum potential resources capable of economic development during the timeframe of this inquiry is probably 50 percent. The minimum of NPR-4 potential resources capable of economic development has been assumed to be 15 percent for the purposes of this analysis.

For purposes of this analysis, it was assumed that 70 percent of the reserves would be produced within 16 years of the commencement of production, or twenty years from the commencement of the hypothetical development program. This adjustment took into account the possible need for this degree of accelerated production in order to make development of NPR-4 economically feasible.

44/ Ref: United States Department of the Interior (DOI), Alaskan Natural Gas Transportation Systems, a Report to the Congress, Pursuant to Public Law 93-153, December 1975 (Exhibit EP231).

The estimated possible peak daily gas volumes from NPR-4 are as follows: 45/

Assumed Portion of Resource Base Capable of Economic Development and Production	Maximum Daily Production Volume (BCF/D)	Maximum Daily Saleable Volume (BCF/D) 46/
15%	0.334	0.284
30%	0.668	0.568
50%	1.115	0.948
70%	1.562	1.328

5. Summary and Conclusions

Exploration of NPR-4 to date has not produced encouraging results. Further exploration of NPR-4 may reveal significant quantities of oil and gas. However, there appears to be no realistic expectation for the discovery of petroleum accumulations in individual fields anywhere near the size of the Prudhoe Bay Field. Most of the oil and gas fields discovered in NPR-4 will probably be scattered, small, and expensive to develop and produce.

The resource potential for NPR-4 of 14.3 Tcf contained in the FEA Report on NPR-4 has been used for this analysis. However, no gas is currently available from NPR-4 for attachment to any of the proposed transportation systems. Furthermore, the only activity now authorized by Congress for NPR-4 is the current seven-year exploration program (FY 1974-FY 1980).

45/ See Exhibit III-7 for details of computations.

46/ Produced volumes reduced by 15% to account for fuel and volume reduction due to removal of liquids and impurities.

EXHIBIT III-7

NAVAL PETROLEUM RESERVE NO. 4 (NPR-4)
PROJECTED GAS AVAILABILITY SCHEDULE
(Based Upon A Hypothetical Development Program)

Resource Base (a)	Assumed Portion of Resource Base Capable of Economic Development and Production (b)	Assumed Portion of Developed Resources That Will Be Produced Within Twenty Years (c)	Total Volume Produced Within Twenty Years (TCF) a/ (d)	Maximum Annual Production Volume (BCF/D) b/ (e)	Maximum Daily Production Volume (BCF/D) c/ (f)	Maximum Daily Saleable Volume (BCF/D) d/ (g)
14.3 Tcf	15%	70%	1.5	122	0.334	0.284
14.3 Tcf	30%	70%	3.0	244	0.668	0.568
14.3 Tcf	50%	70%	5.0	407	1.115	0.948
14.3 Tcf	70%	70%	7.0	570	1.562	1.328

a/ Represents 20 years into a hypothetical development program and 16 years of production (See Text).

b/ Maximum annual production equals total production within twenty years divided by 12.29. See text for assumptions underlying projected production schedule.

c/ Col. (e) ÷ 365

d/ Production volumes are reduced by 15% as an allowance for fuel usage, shrinkage due to removal of liquid hydrocarbons and possible volume reduction due to removal of impurities (e.g., H_2S, CO_2, N_2).

The known oil and gas deposits in NPR-4 have not established any definitive production trends. Therefore, no substantial weight should be given to the planned routes of the proposed transportation systems vis-a-vis the limited amount of gas known to exist and the future possible gas supplies from NPR-4.

The maximum daily saleable gas volumes that can be expected from NPR-4 in the future could range from roughly 0.3 Bcfd to 0.9 Bcfd. These estimates are still highly speculative. Their only intended use is to establish the possible degree of gas transportation system expansibility that may be required. Because of the generally discouraging exploration results on NPR-4 to date, no decisionmaking should hinge on the upper limit of 0.9 Bcfd.

E. Arctic National Wildlife Range

Arctic Gas is the only proposed gas transportation system that would cross the Arctic National Wildlife Range (ANWR). Most of the information included in the FPC record relative to the resource potential of ANWR was presented by Alcan. Alcan estimated that ANWR has the potential for approximately 14.5 Tcf of gas. However, no details were given as to precisely how this estimate was derived. Alcan's potential gas estimates are referenced in particular to the Marsh Creek anticline, a feature identifiable by surface observations, and a "large gravity and magnetic high southeast of Kaktovik, Alaska" (also described in the record as being south of Barter Island). 47/

47/ Ref: Transcript pages 34,443, 34,446-447.

Another description of the petroleum potential of the ANWR is contained in the DOI's Final Environmental Statement related to ANWR. 48/ This report states:

> "The Sadlerochit and Shublik Mountains in the north part of the range are on the same regional uplift as the oil field at Prudhoe Bay, and have the same structural style, the same Carboniferous, Triassic, and Lower Cretaceous reservoir rocks, and the same arrangement of Upper and Lower Cretaceous unconformities as the oil field.
>
> Although the reservoir rocks are exposed in the mountains, they also probably underlie the younger Cretaceous and Tertiary sediments that cover about 5,000 square miles in the Coastal Plain to the north. There is room beneath these young sediments for several structural traps similar to those at Prudhoe Bay. . . .
>
> In addition, the wildlife range has potential reservoir rocks both older and younger than those at Prudhoe Bay. In the oil field, the Mississippian rests on argillite basement, but in the Sadlerochit and Shublik Mountains, 4,000 to 7,000 feet of Devonian and Silurian limestone and vuggy dolomite are present beneath the Mississippian. North of the Sadlerochits, a deep sedimentary basin beneath the Coastal Plain is inferred from a lone regional gravity anomaly. About 10,000 feet

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48/ Department of the Interior, Final Environmental Statement, Proposed Arctic National Wildlife Refuge, Alaska, October, 1974, pp. 57-58.

of folded Cretaceous or Tertiary sediments fill the basin. The presence of oil in some of these sediments is demonstrated by seeps along the coast at Barter Island and Angun (Ungoon) Point and oil-saturated sands outcropping on the lower Katakturuk and Jago Rivers.

A potential oil and gas field of very large accumulation is reported to lie on the coastal plain . . . [reference map is included as Exhibit III-8] just south of Camden Bay and near the mouths of Carter and March Creeks. All available information pertaining to its characteristics and production potential have been provided by the Division of Geological Survey, Alaska Department of Natural Resources. */ This structure is known as the Marsh Creek anticline, where a 40 square-mile uplift is visible on the surface. The potential oil-bearing structure is 46 miles long and covers approximately 150,000 acres.

At least four geologic formations may harbor oil and gas. Permeable marine Tertiary sands appear at the surface, and some possess good residual oil saturation. Cretaceous sediments of productive oil and gas fields to the west should be well developed, and the Sadlerochit sand reservoir of Prudhoe Bay and the underlying Lisburne reservoir should also be present at March Creek.

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*/ Hartman, K.C. 1972. 'Arctic National Wildlife Range Geology and Mineral Resources.' Division of Geological and Geophysical Survey, Alaska Department of Natural Resources.

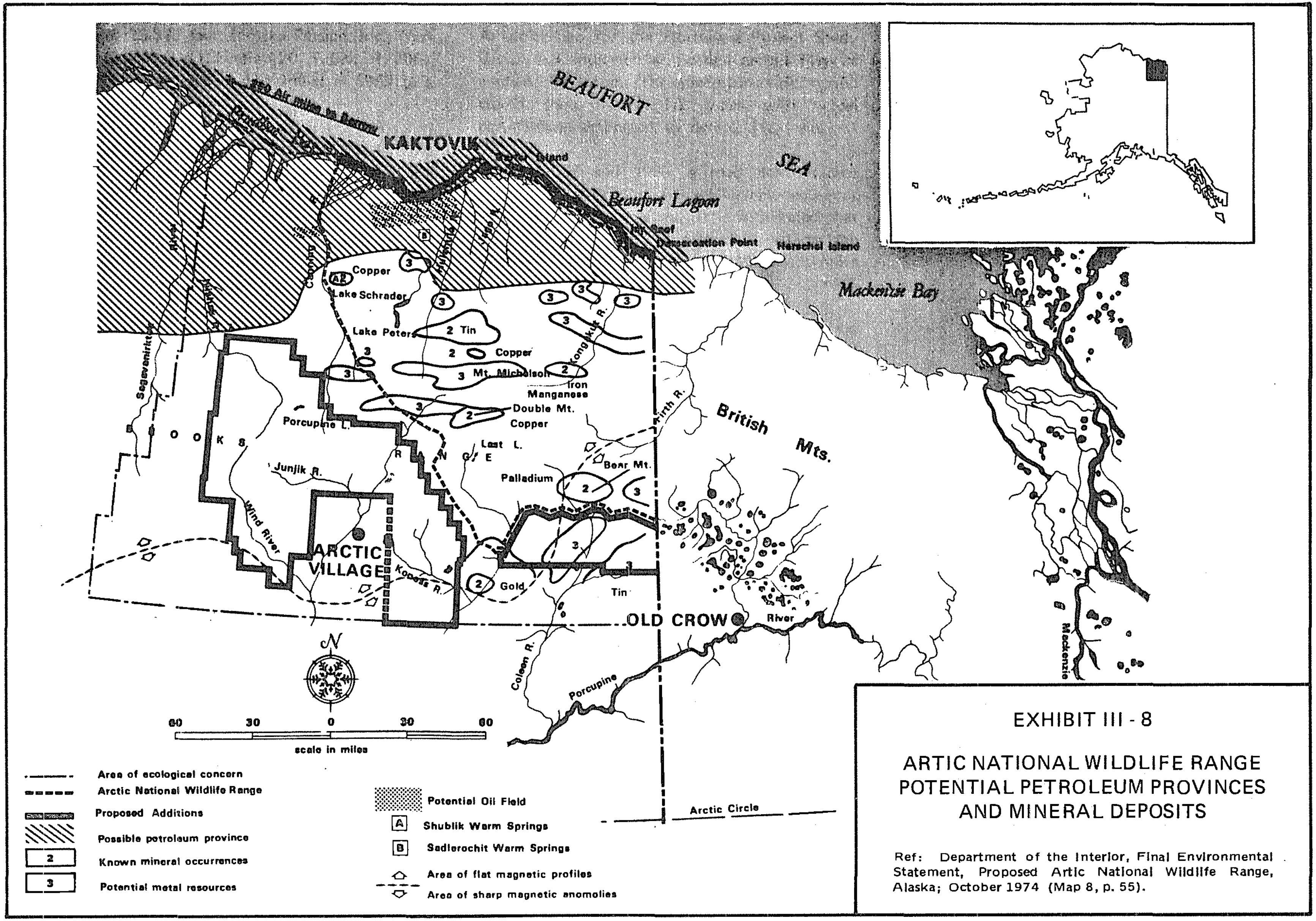

EXHIBIT III - 8

ARTIC NATIONAL WILDLIFE RANGE
POTENTIAL PETROLEUM PROVINCES
AND MINERAL DEPOSITS

Ref: Department of the Interior, Final Environmental Statement, Proposed Artic National Wildlife Range, Alaska; October 1974 (Map 8, p. 55).

> If 150 feet of oil saturation is assumed for each of these formations, there is potential for a six billion barrel oil reserve. . . . Even more optimistic calculations made by the [State of Alaska's] Division of Geological Survey have indicated that a 20 billion barrel potential reserve is entirely reasonable. This may be a highly inflated figure, however, for Alaska's proven oil reserves total only [approximately 10] billion barrels. In addition, the area has been only superficially explored, and no test wells have been drilled."

Currently available information on the petroleum potential of the ANWR appears highly speculative because limited exploration has been conducted on ANWR. Additional exploration (probably at least magnetic, gravity, and seismic surveys) would be required to establish a credible estimate of the petroleum potential of ANWR. No definitive statements can be made relative to the possible magnitude of gas deliverability from the ANWR on the basis of the information currently available to the FPC. The only conclusion that can be drawn at this time from a review of the limited amount of available information is that the ANWR is a <u>potential</u> hydrocarbon bearing area. It should be noted, however, that the Department of the Interior has not opened the ANWR for hydrocarbon exploration and development.

F. Beaufort Sea and Chukchi Sea

Several different potential gas estimates for the Alaska North Slope offshore areas in the Beaufort Sea and Chukchi Sea are included in the record of these proceedings. The State of Alaska's DGGS report 49/ estimates that the gas potential for these offshore areas is 46.5 Tcf. The USGS Circular 725 50/ estimates that the undiscovered,

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49/ See p. III-30, n. 40, for description of report.

50/ See p. III-31, no. 42, for description of report.

recoverable resources for the North Slope offshore area ranges from 5 Tcf at 95 percent probability to 50 Tcf at a 5 percent probability, with a statistical mean of 29 Tcf. It seems apparent from the limited information available that the only definitive statement on the gas resource potential of the offshore Alaska North Slope that can made at this time is that the State of Alaska's 46.5 Tcf estimate is in fairly close agreement with the USGS upper estimate (5 percent probability value) of 50 Tcf.

The record in these proceedings does not contain any evidence which indicates that any gas would be available - at least in the short term - from any Alaska North Slope offshore areas with the possible exception of the offshore area adjacent to the Prudhoe Bay Field. The development and production technology utilized for onshore North Slope operations will probably have to be modified extensively to cope with the added problems of offshore Arctic operations. Whether, and when, any future gas discoveries in the Beaufort Sea and the Chukchi Sea would be capable of economic development and production depends primarily on the size of the discoveries.

Accordingly, no gas transportation system expansibility requirement has been taken into account for the Beaufort Sea and Chukchi Sea, except for the offshore area adjacent to the Prudhoe Bay Field.

G. Interior Basins

Several Alaska interior geological basins were discussed in these proceedings: the Yukon-Kandix Basin, the Middle Tanana Basin, and the Copper River Basin (for location of basins, see Exhibit III-1). Most parties agree that the interior basins of Alaska do not contain promising amounts of gas (about 2 Tcf).

The FPC Staff Brief assesses the basins' potentials as follows:

> "Although the State of Alaska's [1974] gas report assigned large numbers of potential reserves from these areas, recent drilling and other studies by gas producers suggest these basins are almost barren of gas. In the Yukon-Kandix basin the drilling of Louisiana Land and Exploration Company indicated the discouraging presence of several volcanic sequences underlying this area. The only deep well drilled in the Middle Tanana Basin together with the fact that the basin is simply an alluvial plain, clearly rules rules out the presence of significant gas finds. In the Copper River Basin eight wells have been drilled, none of which shows oil or gas accumulations . . . . During producer testimony in this proceeding, neither Phillips Petroleum, Exxon, Atlantic Richfield, BP Sohio, and Mobil, in answering certain interrogatories were enthusiastic about these areas (Tr. Volume 122). Exxon and Atlantic Richfield held extensive leases in these areas, but have since cancelled such leases due to unfavorable drilling and exploration studies (Tr. 19,491; 19,522; 19,869; 20,221; 20,225)." (Br. pp. 7-8).

Alcan claims that the State of Alaska's 1974 report 51/ estimates of 11.4 Tcf of speculative gas reserves for the Yukon-Kandix basin and 1.2 Tcf for the Copper River basin are highly suspect because these estimates were based on the volumetric method of basin assessment. 52/ Alcan

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51/ See p. III-30, n.40 , for description of report.

52/ See p. III-30, n. 41, for description of method.

believes the evidence suggests that the USGS estimate of 2 Tcf of potential reserves for all the interior basins of Alaska, excluding the North Slope basin and the Gulf of Alaska, is much more reasonable. By footnote, Alcan explains that the 2 Tcf value is a statistical mean of USGS estimates which range from 0 Tcf (95 percent probability) to 5 Tcf (5 percent probability). 53/

Based upon the information available at this time, no weight should be given to the routes of the proposed gas transportation systems vis-a-vis the gas resource potential of the Yukon-Kandix Basin, the Middle Tanna Basin, and the Copper River Basin. Furthermore, because of the questionable likelihood of discovering any significant accumulations of natural gas in these basins, it is not necessary to make an estimate of transportation system expansibility requirements for the resource potential of these areas.

53/ However, it should be pointed out that USGS also employed at "70% marginal probability" - i.e., 30% probability of finding no gas in commercial quantities.

H. Mackenzie Delta Area

The desirability and economic feasibility of constructing a joint North Slope-Mackenzie Delta gas transportation system would depend, in substantial part, upon the gas supplies in the Mackenzie Delta area. The benefits of such a common system would result from a sharing of costs for transporting the Alaskan and Mackenzie Delta gas. Arctic Gas is the only proposed transportation system which would handle both North Slope and Mackenzie Delta gas.

Judge Litt concluded that the evidence in the FPC record supported "the finding of a reasonable likelihood of Mackenzie Delta deliveries of not less than 1 Bcf/d in the first year of operations and 1.5 Bcf/d in the fifth year." For the reasons set forth in the following discussion, we believe that Judge Litt's finding with respect to deliverability is not consistent with recently developed data.

Mackenzie Delta gas supply information is now available which was submitted to the Canadian National Energy Board (NEB) after the close of the proceedings before the FPC. 54/ The views of the NEB on the Mackenzie Delta gas supplies (as well as its views on other related matters) are the most authoritative available to us in evaluating the desirability and economic feasibility of a common system to transport both North Slope and Mackenzie Delta gas.

The information submitted to the NEB is based upon the results of more recent Mackenzie Delta exploration than was available when the information submitted in the FPC proceeding was prepared.

Each of the subject gas supply presentations before the NEB are identified in the synopses appearing in Appendix III-A of this chapter.

A summary of the reserves estimates for the various Mackenzie Delta fields is shown on Exhibit III-9. The locations of the various field are shown on Exhibit III-10.

54/ Re: Gas supply information filed in Phase 4 of the Mackenzie Valley-Yukon Pipeline Hearing.

EXHIBIT III-9

SUMMARY OF VARIOUS ESTIMATES OF MACKENZIE DELTA GAS RESERVES
(BCF)

FIELD	ARCTIC GAS FPC Filing 1/ Proven	ARCTIC GAS FPC Filing 1/ Total	ARCTIC GAS NEB Filing 2/ Proven	ARCTIC GAS NEB Filing 2/ Total	FOOTHILLS FPC Filing 1/ Proven	FOOTHILLS FPC Filing 1/ Total 3/	FOOTHILLS NEB Filing 2/ Proven	FOOTHILLS NEB Filing 2/ Total	PRODUCERS NEB Filing 2/ Total
Adgo	78	249	44	293	-	1,500	87	165	185 a/
Garry	-	-	103	306	-	-	154	154	-
Kumak	-	-	15	18	-	-	-	-	- c/
Mallik	60	437	21	219	-	200	19	79	100 a/
Netserk	-	-	19	46	-	-	58	63	115 a/
Niglintgak	315	657	409	708	-	1,000	488	753	1,012 b/
Parsons Lake	532	1,485	1,558	1,706	-	1,500	1,236	1,454	-
Reindeer	5	18	3	38	-	100	1	11	- c/
Taglu	2,728	2,790	2,689	2,822	-	2,700	2,712	2,712	3,430 a/
Titalik	10	181	32	151	-	100	-	133	- c/
Ya Ya-North	97	392	31	159	-	200	64	75	-
Ya Ya-South	-	-	134	275	-	200	70	121	-
Total	3,826	6,209	5,060	6,741	-	7,500	4,889	5,718	- d/

1/ Filed in Docket No. CP75-96, *et. al*. Does not reflect 1975-76 winter drilling.

2/ Filed January, 1977, with NEB. Based on information available through December, 1976.

3/ Expressed as "most likely" reserves.

a/ Imperial Oil Limited.

b/ Shell Canada Limited and Shell Resources Limited.

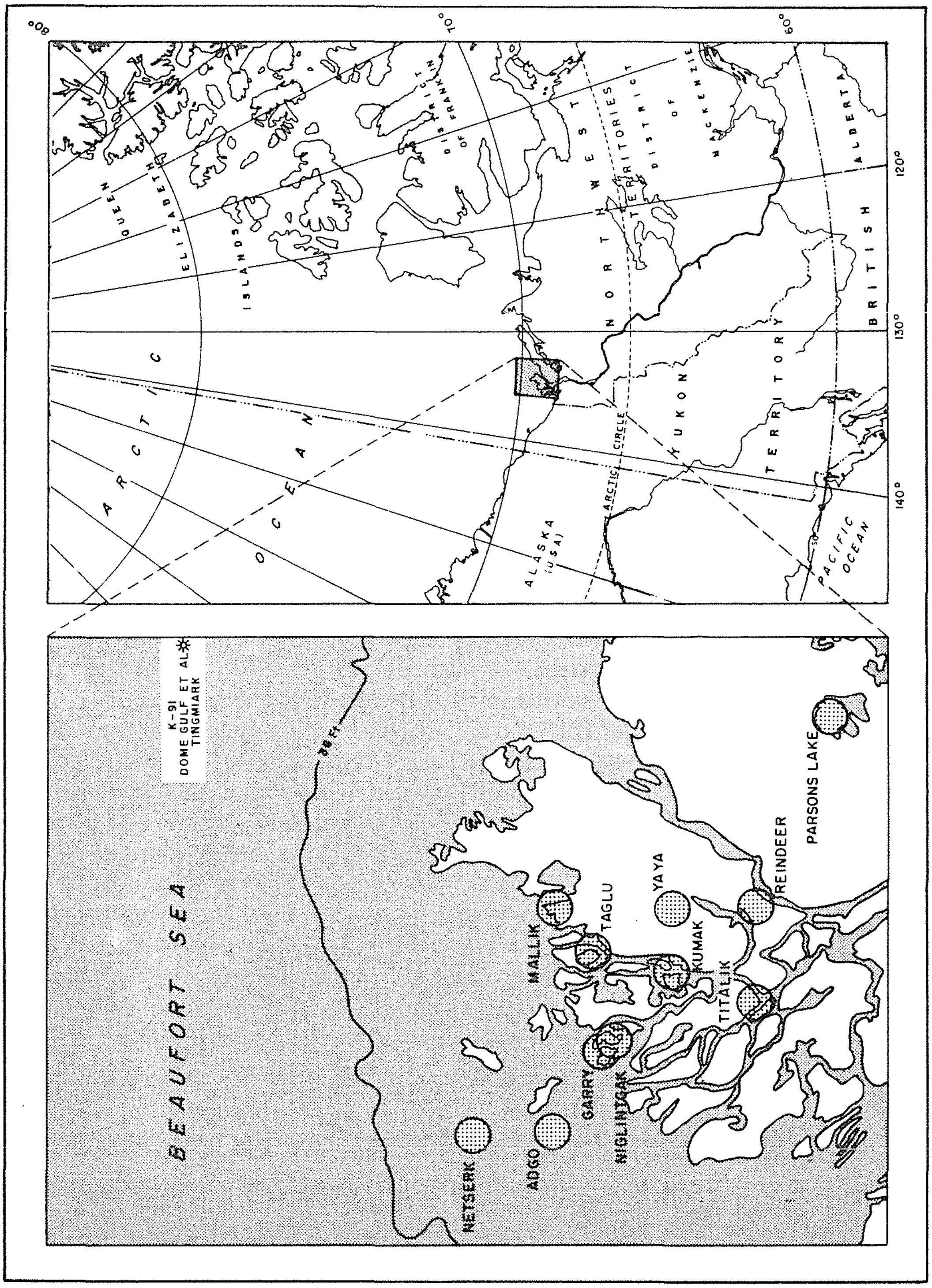
c/ Shell stated: Development of these accumulations is very speculative at this time.

d/ Gulf Oil Canada Limited stated: Proved reserves are about 4.3 Tcf, and there are no proved or probable gas reserves to date in the deep Beaufort Sea, but a gas show was encountered at Dome-Gulf Tingmiark K-91 in 1976. (See Exhibit III-12).

Note: CPA estimates reserves @ December 31, 1976, as follows: Proved ----------------- 4.3 Tcf
Probable (including proved) 6.7 Tcf

EXHIBIT III-10

MACKENZIE DELTA AREA
LOCATION MAP



Ref: Canadian Arctic Gas Pipeline, Limited Submission to NEB in Phase 4 of Mackenzie Valley - Yukon Hearing. Map prepared by Sproule Associates, Ltd., Calgary, Alberta.

The Mackenzie Delta area has not been fully explored, and many of the known deposits of oil and gas have not yet been fully developed. Additional exploration will most likely result in new discoveries. Future development drilling will better delineate existing fields and should result in reserve additions to the existing fields. However, exploration and development activities to date have not been totally encouraging, and the magnitude and timing of future reserves is uncertain. The three largest fields discovered to date have reserves (including proved, probable, and possible) of approximately 3 Tcf, 1.5 Tcf, and 1 Tcf (Taglu, Parsons Lake, and Niglintgak, respectively). No other field discovered so far has reserves (again, including proved, probable, and possible) in excess of 0.2 Tcf or 0.4 Tcf, according to the recent estimates by Foothills and Canadian Arctic, respectively. There is no information presently available which would indicate that the future Mackenzie Delta discoveries (at least with respect to the onshore and shallow water area) would be different from fields discovered to date. If it is assumed that the best presently known onshore prospects have already been drilled, the future onshore discoveries are likely to be even smaller than the existing fields.

There is some expectation that structures in the Mackenzie Delta offshore area in the Beaufort Sea could hold substantial amounts of hydrocarbons. However, estimates of the gas potential for the offshore area are even more speculative that the onshore gas potential estimates. Added technological problems will be encountered in the offshore Beaufort Sea area, and offshore operations in the Arctic area will undoubtedly be expensive. Offshore discoveries should therefore be larger than onshore discoveries in order to make them economically producible. But only three of the Mackenzie Delta fields discovered to date have total (proved, probable and possible) reserves in excess of 1 Tcf. The pattern of onshore discoveries to date makes the likelihood of realizing any additions of reserves from the offshore Mackenzie Delta area - at least during the near future - highly questionable.

Most of the Mackenzie Delta discoveries to date have been non-associated gas (i.e., gas in gas reservoirs and not associated with oil). No current plans are known for marketing any oil discovered or for marketing liquids which may have to be separated from the gas before the gas can be transported. Present indications are that the revenues from Mackenzie Delta gas will have to support fully all the exploration, development, and production activities in the area.

It could be argued that the presence of a gas transportation system in the area would result in a rapid escalation of drilling activity. However, if the best onshore prospects have already been drilled, and if technological and economic considerations require a high degree of selectivity for offshore activities, no appreciable escalation in drilling activity is guaranteed by the mere presence of a gas transportation system.

The rate of reserves additions in the past, when most drilling activity was conducted onshore, does not provide a valid basis for projecting the level of reserves additions that may occur in the future when much of the drilling activity may be offshore. Additionally, the reserves additions resulting from future onshore activities will not necessarily follow the past pattern of reserves additions, particularly if the best onshore prospects have already been drilled.

El Paso contends, in effect, that only "saleable gas production from proved reserves from the commercial fields" should be considered. According to El Paso, the only commercial fields are the three largest fields (Taglu, Niglintgak, and Parsons Lake) and their combined deliverability is only 0.5 Bcf/d. El Paso bases its contention, in part, upon its belief that the producers are considering gas processing plants for only these fields and, therefore, no other fields would be produced. 55/ However, recent NEB submissions by

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55/ Ref: Brief on Exceptions of El Paso Alaska Company, p. 428.

Foothills Pipe Lines, Ltd. and Imperial Oil Limited indicate that plants at the largest fields will also be used to process gas from some of the other fields. El Paso also mentions the reduction made by the Canadian Petroleum Association (CPA) in proved reserves from 3.96 Tcf as of December 31, 1974 to about 2.9 Tcf as of December 31, 1975. 56/ However, the CPA estimates the Mackenzie Delta proved reserves as of December 31, 1976 to be 4.3 Tcf. 57/

A very recent report issued by Canada's Department of Energy, Mines and Resources states:

> ". . . Exploration activity to date has concentrated mainly on the onshore delta prospects and the prospects that can be explored from man-made islands. The greatest remaining potential appears to lie in the offshore area, where the rate of exploration will be controlled by the ability to construct islands and the availability of specialized drill ships. The Beaufort Sea is one of the most logistically difficult areas in Canada and the rate of exploration is expected to be slow.
>
> The discoveries to date as well as the estimated hydrocarbon potential indicate that the resource of the region will be dominantly gas, but there is a significant oil and NGL potential. . . .Because of the deltaic nature of the Tertiary deposits in this area, it is expected that there will be a large number of modest-sized pools, which will make it difficult to estimate the portion of the resources in this area that may become economic. In addition, this type of geological sequence suggests that the fields may be broken into many pools by abundant

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56/ *Ibid*., p. 426.

57/ Ref: CPA News Release and Press Conference, March 4, 1977.

normal faults; moreover, numerous reservoirs may be stacked above one another, so that multiple pay zones may be anticipated in any one structure. Both these characteristics will add further complications to an economic analysis. Another problem in estimating the economic portion of the resources is that in many cases, both gas and oil may have to be produced from the same reservoir." 58/

Summary and Conclusions

No rapid or substantial long-term growth in gas reserves in the Mackenzie Delta area can be projected at this time on the basis of the information available to the FPC. Almost all the exploratory and development activity that has occurred to date has been onshore. These past activities have not been encouraging. The three largest fields discovered to date are credited with reserves of approximately 3 Tcf, 1.5 Tcf, and 1 Tcf (including proved, probable, and possible reserves). The offshore potential reserves estimates appear to be highly speculative. Offshore exploration, development, and production will be limited by technological and economic constraints.

Based upon all of the information available to the FPC, the most realistic level of gas availability from the Mackenzie Delta area that can be projected at this time is 1 Bcf/d. This 1 Bcf/d deliverability could be met initially (at least in very substantial part) by the three so-called "start-up" fields (Taglu, Parsons Lake, and Niglintgak). In order to sustain the projected 1 Bcf/d deliverability for twenty years, additional reserves amounting to an approximate doubling of the claimed 3.8 Tcf level of proved reserves as of July, 1975 59/ would be required. In order to sustain

58/ Department of Energy, Mines and Resources, Report EP77-1, "Oil and Natural Gas Resources of Canada 1976", p. 31.

59/ This level of proved reserves was supported by Alaskan Arctic before the FPC. However, see synopses of recent submissions to NEB by Canadian Arctic, Foothills, and Gulf Canada (App. III-A). These companies' recent estimates of Mackenzie Delta proved reserves are 5.1, 4.9, and 4.3 Tcf, respectively.

the 1 Bcf/d deliverability for thirty years from the Mackenzie Delta area (Prudhoe Bay Field gas could possibly be available for up to 35 years; see pp. III-5 to III-10), cumulative marketable reserves of 11 Tcf would be required.

However, if future Mackenzie Delta exploratory efforts result in the discovery of more fields - and particularly larger fields - than have been discovered through past exploratory efforts, the above judgment of deliverability of 1 Bcf/d could prove to be an understatement of the pipeline capacity required to handle Mackenzie Delta gas. As a basis for establishing the degree of pipeline system expansibility that may be required to handle gas supplies in excess of 1 Bcf/d, it is conceivable that the Mackenzie Delta area deliverability (including substantial offshore gas) could be sustained at 1.5 Bcf/d or even higher. 60/ Therefore, the degree of gas transportation expansibility that should be attributed to the Mackenzie Delta area is 0.5 Bcf/d.

Finally, the current plans for operating the Mackenzie Delta fields include utilizing several centrally located gas conditioning plants to handle gas produced from all of the fields. The mode of field operations will most likely be sequential production of various fields rather than simultaneous production of all or a substantial number of fields. 61/ The above projected gas deliverabilities are consistent with this possible mode of field operations. Even if the most optimistic of recent estimates of current reserves (including proven, probable, and possible categories) is accepted, 62/

60/ If some of the very optimistic projections by the producers are ever realized, none of the gas transportation systems suggested to date would be of sufficient capacity. See, for example, Dome Petroleum referenced in Initial Decision, p. 43. Also, see synopsis of Imperial Oil's submission to NEB, Appendix III-A.

61/ This mode of operations is inferred in the FPC record. Also see synopses of submissions to NEB by especially Foothills and Gulf Canada, Appendix III-A.

62/ See, for example, recent reserves estimates by Canadian Arctic submitted to NEB, Appendix III-A.

it seems questionable whether gas delivery rates substantially greater than 1 Bcf/d could be sustained long enough to justify expenditures for gas processing facilities capable of handling volumes greater than 1 Bcf/d. 63/ In the event the gas discoveries are slightly higher in the near term than is anticipated in the above analysis, economic constraints would probably defer their immediate availability to a gas transportation system.

63/ See Appendix III-A, Table III-A-2.

APPENDIX III-A

Synopses of Recent Submissions to the National Energy Board* Related to Gas Supply in the Mackenzie Delta Area

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*Submissions for Phase 4 in the Matter of the National Energy Board Mackenzie Valley - Yukon Hearing, Order AO-9-GH-1-76. The NEB submissions by Canadian Arctic and Foothills were also filed with the FPC after the close of the proceedings before the FPC.

Canadian Arctic Gas Pipeline Limited Submission to NEB

Canadian Arctic Gas Pipeline Limited's (Canadian Arctic) submitted a report to the NEB relating to Mackenzie Delta gas supplies entitled, "Estimates of the Natural Gas Reserves and Deliverability, Mackenzie Delta Area, Northwest Territories (as of January, 1977)." Canadian Arctic stated that the report was derived from data available to its consultant, Sproule Associate Limited, to year-end 1976. The current individual field reserves estimates and the deliverability forecast by Arctic Gas area shown on Tables III-A-1 and III-A-2, respectively (pp. III-A-3 and 4).

A comparison of the Mackenzie Delta gas supplies as estimated by Arctic Gas in the FPC proceedings, based upon results prior to the 1975-76 winter drilling, and by Canadian Arctic in the NEB proceeding, based upon information available through year-end 1976, is as follows:

	Arctic Gas Estimates A/	Canadian Arctic Up-Dated Estimates B/
Proven Reserves	3.8 Tcf	5.1 Tcf
Probable Reserves	0.8	0.7
Possible Reserves	1.6	0.9
Total	6.2 Tcf	6.7 Tcf

A/ See for example Arctic Gas Brief on Gas Supply Isssues, page 10.

B/ See Table III-A-1.

Canadian Arctic states that the most reasonable projection for utimate gas reserves in the Mackenzie Basin is between 40 and 60 Tcf. The company emphasizes that a large portion of this potential reserves is in the speculative category and that their existence would have to be established by drilling.

The essence of Canadian Arctic's recent submission to the NEB appears to be an update of information previously submitted to the Board. This updated information shows an eight percent increase in total reserves and a general reclassification of reserves from the possible and probable categories to the proven category. The proven reserves are increased by 1.3 Tcf, or roughly 20 percent over estimates cited in the FPC proceedings by Arctic Gas.

Table III-A-1

CANADIAN ARCTIC GAS PIPELINE LIMITED A/

Estimate of Natural Gas Reserves
(As of January, 1977) B/

Mackenzie Delta Area

Field	Proven MMCF	Probable MMCF	Possible MMCF	All Reserves MMCF
Adgo	43,700	107,300	141,500	292,500
Garry	103,100	172,900	29,700	305,700
Kumak	15,100	2,800	-	17,900
Mallik	21,100	61,000	136,400	218,500
Netserk	19,100	26,800	-	45,900
Niglintgak	409,100	63,300	235,600	708,000
Parsons Lake	1,558,000	94,400	53,900	1,706,300
Reindeer	3,400	10,700	23,800	37,900
Taglu	2,689,400	133,000	-	2,822,400
Titalik	32,000	23,700	95,300	151,000
Ya Ya - North	31,400	17,700	110,700	159,800
Ya Ya - South	134,400	23,300	117,300	275,000
Total	5,059,800	736,900	944,200	6,740,900

A/ Submission to National Energy Board for Phase 4 in the matter of Mackenzie Valley-Yukon Hearing.

B/ Study prepared by Sproule Associates Limited.

III-A-4

CANADIAN ARCTIC GAS PIPELINE LIMITED 1/

Estimated Gas Deliverability 2/

Mackenzie Delta Area

TOTAL DELIVERABILITY FORECAST

Year	Daily 3/ MMCF/D	Max. Capability at Year End 4/ MMCF/D	Annual BCF/Yr.	Cumulative BCF
1	925	2,535	335.6	335.6
2	925	2,195	335.6	671.2
3	925	1,878	335.6	1,006.8
4	925	1,591	335.6	1,342.4
5	925	1,329	335.6	1,678.0
6	925	1,086	335.6	2,013.6
7	925	1,025	335.6	2,349.2
8	925	939	335.6	2,684.8
9	925	943	335.6	3,020.4
10	925	925	335.6	3,356.0
11	925	925	335.6	3,691.6
12	925	908	335.6	4,027.2
13	908	880	328.1	4,355.3
14	880	834	317.6	4,672.9
15	834	788	301.5	4,974.4
16	788	722	284.9	5,259.3
17	722	664	261.5	5,520.8
18	664	582	240.9	5,761.7
19	582	513	210.7	5,972.4
20	513	454	185.1	6,157.5
21	454	276	148.1	6,305.6
22	276	242	99.2	6,404.8
23	242	138	82.5	6,487.3
24	138	124	49.5	6,536.8
25	124	108	44.0	6,580.8
Remaining			160.1	6,740.9

1/ Submission to National Energy Board for Phase 4 in the matter of Mackenzie Valley-Yukon Hearing.
2/ Study prepared by Sproule Associates Limited.
3/ Average daily rate for year based on contract take of 1 MMCF/D per 7,300 MMCF reserves.
4/ Based on computed maximum deliverability.

Note: The above deliverability forecast is predicated upon full development of the estimated reserves shown on Table A-1.

Foothills Pipe Lines Ltd. Submission to NEB

Foothills Pipe Lines Ltd. (Foothills) submitted to the NEB a report dated January, 1977 and supporting testimony dated January 19, 1977, relating to the Mackenzie Delta area gas supplies. This report appears to be, in substantial part, an update of an earlier Foothills report dated April, 1975. The recent report apparently reflects Foothills' views on the Mackenzie Delta area gas supply based upon the most recent information available. A summary of Foothills reserves and deliverability forecasts for the Mackenzie Delta area are shown on Tables III-A-3 and 4, respectively.

The January, 1977, Foothills submission to the NEB included estimated reserves for the existing discoveries of 5.7 Tcf, including proven, probable, and possible reserves. In Foothills' previous submission to NEB (April, 1975) and in Foothills' Brief filed in the FPC proceeding, the company had estimated the "most likely" reserves to be 7.5 Tcf. Foothills explained in its FPC Brief that "the designation 'most likely' refers to that quantity of gas, which on an engineering basis, will ultimately be produced from the reservoir." 1/

Foothills envisions that the initial gas production from the Mackenzie Delta will come from three "start-up" fields: Niglintgak, Parsons Lake, and Taglu. As a basis for projecting gas production rates, Foothills established the following guidelines:

1) Pipeline demand to be met by the three start-up fields for as long as possible.

2) Pipeline demand to be 0.8 Bcfd commencing November 1, 1982, increasing 0.4 Bcfd annually to a maximum of 2.4 Bcfd in 1986.

3) Economic constraints not included.

1/ Foothills' Brief, p. 4, n. 4.

Based on these guidelines and its reserves estimates Foothills projected that the three start-up fields should be capable of meeting pipeline demand for the first three years, peaking in the fourth year at 1.985 Bcfd. Foothills had previously forecasted (April, 1975, submission to NEB) that the three fields would be capable of meeting pipeline demand for the first four years and peak in the fifth year at 2.157 Bcfd.

Foothills projects the ultimate gas potential of the Mackenzie Delta area to be as follows: 2/

Onland Mackenzie Delta	7.0 Tcf
Offshore Shallow (Man-made island zone)	5.0
Offshore Deep	18.0
Total	30.0

A possible mode of operation for the Mackenzie Delta area is suggested by Foothills as follows:

"Because the Beaufort Basin is a difficult operating area and because most of the gas reserves will be located offshore, there should be a master plan for the employment of certain facilities. For example, efficiency in this very expensive operating area will require building as few gas plants as possible and maximizing their use. The Taglu, Parsons Lake and Niglintgak gas plants should serve at maximum capacity throughout the productive life of the basin as opposed to declining throughput based on the life of a pool or a few pools. These plants and a very few more that are strategically located should satisfy processing requirements. This assumes that all producers would use a few major facilities to maximize efficiency, minimize investment and to reduce environmental disturbances. . .Historically, practically all new gas and oil transmission lines have been filled and initially provided for by a very few key pools. This start-up procedure is not

2/ Foothills projects an additional 4.4 Tcf ultimate gas potential for Mainland Northwest Territories south of Latitude N. 68°.

unique to Canada; it is a worldwide practice. There is but one essential requirement. The key pools must have the deliverability and reserves for this inital period to support requirements until additional supplies can be placed onstream."

"Production practice in the Beaufort Basin is expected to be somewhat different than that in established areas. To a greater extent and in amount, pools are likely to be produced sequentially as opposed to simultaneously. Key discovered pools are large and capable of high-productivity. These can readily carry the initial load. This allows the lead-time necessary to place onstream other pools which will be capable of carrying a major part of the load as key pools decline. The nature of the environment (onshore-offshore), seasonal operations, maximum use of gas plants, common usage of equipment and personnel all point to a hgiher degree of sequential pool production. It should be the most efficient pattern to provide gas to consumers at lowest cost and yet enhance profitability."

"The concept of sequential pool production at high deliverability is consistent with the reservoir characteristics of the discovered pools. Pools, as yet undiscovered, are expected to have similar characteristics." (p. 1-A-102)

FOOTHILLS PIPE LINES LTD. 1/

January, 1977

ESTIMATED MARKETABLE GAS RESERVES

MACKENZIE DELTA AREA

Foothills' Current Estimates 1/

Field	Proven MMCF	Probable MMCF	Possible MMCF	All Reserves	Foothills' Previous Estimates 2/ All Reserves
Adgo	87,000	20,500	57,900	165,400	1.5
Garry	154,100	--	--	154,100	--
Kumak	--	--	--	--	--
Mallik	19,400	13,200	46,300	78,900	0.2
Netserk	57,900	--	4,600	62,500	--
Niglintgak	487,700	65,900	199,000	752,600	1.0
Parsons Lake	1,236,200	184,000	34,100	1,454,300	1.5
Reindeer	1,100	2,400	7,500	11,000	0.1
Taglu	2,711,800	--	--	2,711,800	2.7
Titalik	--	18,100	114,500	132,600	0.1
Ya Ya - North	64,000	10,500	--	74,500	0.2
Ya Ya - South	69,600	44,500	6,500	120,600	0.2
Total	4,888,800	359,100	470,400	5,718,300	7.5

1/ Submission to National Energy Board for Phase 4 in the matter of Mackenzie Valley-Yukon Hearing, January, 1977.

2/ Submission to National Energy Board, April, 1975. Also, see Foothills' Brief in FPC proceedings.

Foothills Pipe Lines Ltd. 1/

January, 1977

GAS DELIVERY FORECAST

NIGLINTGAK, PARSONS LAKE, TAGLU AND TOTAL

YEAR COMMENCING NOVEMBER 1	NIGLINTGAK AREA DELIVERABILITY			PARSONS LAKE AREA DELIVERABILITY			TAGLU AREA DELIVERABILITY			PIPELINE REQUIREMENTS (MMCFD)	TOTAL DELIVERABILITY OF FIELDS		
	DAILY (MMCFD)	ANNUAL (BCF)	CUMULATIVE (BCF)	DAILY (MMCFD)	ANNUAL (BCF)	CUMULATIVE (BCF)	DAILY (MMCFD)	ANNUAL (BCF)	CUMULATIVE (BCF)		DAILY (MMCFD)	ANNUAL (BCF)	CUMULATIVE (BCF)
1982	122	44.7	44.7	237	86.4	86.4	441	160.9	160.9	800	800	292.0	292.0
1983	184	67.0	111.7	355	129.7	216.1	661	241.3	402.2	1,200	1,200	438.0	730.0
1984	245	89.3	201.0	474	172.9	389.0	881	321.8	724.0	1,600	1,600	584.0	1,314.0
1985	306	111.7	312.7	592	216.1	605.1	1,087	396.7	1,120.7	2,000	1,985	724.5	2,038.5
1986	324	118.1	430.8	710	259.3	864.4	903	329.6	1,450.3	2,400	1,937	707.0	2,745.5
1987	237	86.5	517.3	680	248.4	1,112.8	738	269.4	1,719.7	2,400	1,655	604.3	3,349.8
1988	187	68.3	585.6	536	195.8	1,308.6	613	223.7	1,943.4	2,400	1,336	487.8	3,837.6
1989	148	54.0	639.6	269	98.2	1,406.8	512	187.0	2,130.4	2,400	929	339.2	4,176.8
1990	117	42.7	682.3	131	47.7	1,454.5	428	156.2	2,286.6	2,400	676	246.6	4,423.4
1991	93	33.7	716.0				357	130.4	2,417.0	2,400	450	164.1	4,587.5
1992	73	26.6	742.6				298	108.9	2,525.9	2,400	371	135.5	4,723.0
1993	27	9.9	752.5				140	51.0	2,576.9	2,400	167	60.9	4,783.9
1994							75	27.4	2,604.3	2,400	75	27.4	4,811.3
1995							66	24.1	2,628.4	2,400	66	24.1	4,835.4
1996							58	21.2	2,649.6	2,400	58	21.2	4,856.6
1997							51	18.8	2,608.4	2,400	51	18.8	4,875.4
1998							46	16.7	2,685.1	2,400	46	16.7	4,892.1
1999							40	14.8	2,699.9	2,400	40	14.8	4,906.9
2000							33	11.9	2,711.8	2,400	33	11.9	4,918.8

1/ Submission to National Energy Board for Phase 4 in the matter of Mackenzie Valley-Yukon Hearing.

Table III-A-4

Gulf Oil Canada Limited Submission to NEB

Gulf Oil Canada Limited's (Gulf Canada) submission to the NEB, as it relates to this discussion, is entitled, "The Supply and Demand for Natural Gas."

With respect to the Mackenzie Delta area, Gulf Canada states that the "estimated proved ultimate gas reserves for the Mackenzie Delta area at December 31, 1975 (excluding the deep Beaufort Sea) were 2,850 Bcf, based on submissions to the NEB in 1975 . . . and that drilling and geological and engineering studies during 1976 have increased the proved reserves to about 4,300 Bcf." Gulf Canada points out that there are no proved or probable gas reserves to date in the deep Beaufort Sea, but a gas show was encountered at Dome-Gulf Tingmiark K-91 in 1976. 3/

Gulf Canada states that the projected initial gas processing plants' capacity to handle Mackenzie Delta gas is 0.9 Bcf/d, and that current planning includes some future possible expansion of these plants if sufficient reserves are available. The company expresses its view that "expansion of production from the Mackenzie Delta is not foreseen, but the Beaufort Sea has a relatively large production potential." It is this company's opinion that the earliest production from the Beaufort Sea would be 1986 but that initial production could be several years later.

3/ See Exhibit III-10, p. III-47

An "ultimate reserve potential" of 50 Tcf for the combined Mackenzie Delta Beaufort Sea area is projected by Gulf Canada. The company projects available gas supplies from the area as follows:

Year	Mackenzie Delta	Beaufort Sea
1982	450 MMCF/D	-
1983	900	-
1985	900	-
1986	960	500 MMCF/D
1987	1,025	800
1988	1,025	1,450
1989	1,085	1,700
1990	1,150	1.900
1991	1,150	1,900
1992	1,150	2,000
1993	1,150	2,000
1994	1,150	2,000
1995	1,150	2,000

Imperial Oil Limited Submission to NEB 4/

Imperial Oil Limited's (Imperial) gas supply submission to the NEB, as related to this discussion, was directed at the gas reserves and deliverability of its Mackenzie Delta discoveries. Imperial's estimates of the marketable gas reserves in its four discoveries are as follows:

Field	Marketable Reserves
Taglu	3,030 Bcf
Adgo	185
Mallik	100
Netserk North	115
Total	3,430 Bcf

Of the total 3,430 Bcf of total marketable reserves, Imperial stated that approximately 3,305 Bcf are non-associated gas and 125 Bcf are associated gas. Imperial also has a small share of Titalik Field reserves and holds rights to lands on the edge of the Parsons Lake and Kumak (Niglintgak) Fields; however, Imperial submitted data on only the four above listed Fields.

Imperial estimates that the Taglu Field can maintain a constant production rate of 410 MMcf/D for 15 years prior to decline. This deliverability is premised upon a contract rate of 1 MMcf/D for each 7,300 MMcf of reserves. However, Imperial states that under the terms of its gas sales contracts, "Taglu could be produced at higher production rates if reserves from other fields which are delineated but not yet developed are pooled for contractual purposes." Imperial adds that "from a reservoir depletion viewpoint, there would be no concern about producing Taglu at two or three times its

4/ Ref: Testimony of B.D. Stewart, pp. 1-3; Testimony of B.D. Stewart and R.O. Grieve, p. 2, 4; Exhibit C.

normal contract rate." Imperial states that individual well deliverabilities are expected to average 35 to 50 MMcf/D and that ultimately 20 to 30 wells might be drilled in the Taglu Field.

In regard to the smaller Adgo, Mallik, and Netserk North Fields, Imperial stated that the economics of developing these fields depends on costs, prices, and sharing of facilities. Imperial clarifies that "at this point in time, knowing that the basic production strategy will be to use the centralized processing plant at Taglu and with exploration continuing in the same general areas, we expect these fields will be economical to develop . . . [and] there is a potential for reserve increases in Adgo and Netserk North with further delineation drilling."

With respect to the future gas potential of the Mackenzie Delta/Beaufort Sea area, Imperial presented a "Base Case forecast which represents Imperial's best estimate of the future gas production and a range above and below that level that could reasonably be expected to occur due to the many uncertainties in the forecast calculations." The forecasts assumed continued success for on-going exploration programs both onshore and offshore to a 200-foot water depth. Production from pools discovered onshore or within the 60-foot water depth was forecast to be available five to eight years after discovery. A delay of nine years was forecast for discoveries in the 60 to 100-foot water depth range. As perceived by Imperial, the future gas availability for the Mackenzie Delta/Beaufort Sea area is as follows: Production would commence in 1982, assuming Canadian Arctic is approved for construction in 1977. Current discovered reserves could supply 0.3 Tcf/year (0.8 Bcf/D). Predicated upon Imperial's "Base Case," production could grow to 1.0 Tcf/year (2.7 Bcf/D) in the 1990's, or with greater exploration success than assumed in the "Base Case," production could exceed 1.5 Tcf/year (4.1 Bcf/D) in the 1990's. 5/ Imperial

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5/ Assuming a contract rate of 1 MMcf/D per 7,300 Mcf reserves, the above production rates of 0.8, 2.7, and 4.1 Bcf/D translate into projected reserves of 5.8 Tcf, 19.7 Tcf, and 29.9 Tcf, respectively.

quite properly adds, however, that "lower volumes would result if exploration success is less than assumed in the Base Case."

Shell Canada Limited and Shell Canada Resources Limited Submission to NEB

Shell Canada Resources (Shell Canada) is the operator of the Niglintgak Field. The portion of Shell Canada's submission to the NEB which is relevant to this discussion was entitled "Non-Associated Natural Gas Reserves and Annual Production Forecast, Niglintgak Field, Mackenzie Delta Northwest Territories."

Shell Canada estimated the proven, probable and possible reserves for the Niglintgak Field to be 607 Bcf, 366 Bcf, and 39 Bcf, respectively (1,012 Bcf in total). Based upon an assumed contract rate of 1 MMcf/D per 8,000 MMcf reserves and full development of the total projected reserves of 1,012 Bcf, Shell Canada projected a deliverability of 46 Bcf/year (0.1 Bcf/D). This company also projected that the Niglintgak Field could be sustained at a production rate of 46 Bcf/year for approximately 13 years and that production would decline at approximately 9.5 percent per year thereafter.

This company also stated that it, either singularly or jointly with Imperial Oil Limited and Gulf Oil Canada Limited, has participated in wells in the Kumak, Reindeer, and Titalik Fields. Shell Canada's evaluations indicate that its discovered possible reserves in these three fields are on the order of 100 Bcf. The company states that development of these accumulations is very speculative at this time.

APPENDIX III-B

Listing of Technical Documents Utilized in the Preparation of This Chapter of the Report But Which Were Not Included in the Record of the FPC Proceedings

Listing of Technical Documents Utilized in the Preparation of This Chapter But Which Were Not Included in the Record of the FPC Proceedings

General References

National Petroleum Council; Future Petroleum Provinces of the United States; July, 1970.

Smith and Mertie; Geology and Mineral Resources of Northwestern Alaska; 1930. USGS Bulletin 815.

Prudhoe Bay Field References

"The Determination of Equitable Pricing Levels For North Slope Alaskan Crude Oil," November, 1976; Prepared for FEA by Mortada International, Dallas, Texas.

"Study of Reserves, Hydrocarbons In-Place, Production Rates and Present and Projected Capacities, December 31, 1974, Prudhoe Bay Field, North Slope, Alaska;" Prepared for FEA by James A. Lewis Engineering, Dallas, Texas.

Naval Petroleum Reserve No. 4 References

"The Exploration, Development, and Production of Naval Petroleum Reserve No. 4," July 19, 1976; Prepared for FEA by Resource Planning Associates, Cambridge, Mass.

Office of Naval Petroleum and Oil Shale Reserves; "Annual Report of Operations"; October 1, 1976.

Arctic National Wildlife Range References

Department of the Interior; Final Environmental Statement, Proposed Arctic National Wildlife Range, Alaska; October, 1974.

Hartman, D.C.; "Geology and Mineral Evaluation of the Arctic National Wildlife Range, Northeast Alaska," Open File Report 22; 1972 (Rev.1973); State of Alaska, Department of Natural Resources, Division of Geological and Geophysical Surveys.

Mackenzie Delta References

All submissions to NEB referred to in Appendix III-A this portion of the report.

Foothills Pipe Lines Ltd.'s submission to NEB, dated April, 1975, and entitled "Part 1 - Supply and Requirements."

CHAPTER IV

NET NATIONAL ECONOMIC BENEFIT AND THE COST OF SERVICE

A. Introduction

The relative economics of each Alaskan gas transportation system are fundamental to the decision on a route. Two major yardsticks can be used to make economic comparisons. One criterion for comparing the economic benefits of the proposed systems is net national economic benefit (NNEB). NNEB measures the real benefits and costs to the entire Nation that would be expected from the construction and operation of a system. Benefit and cost to the entire Nation are the standard, not the effect on any particular region or sector of the economy. This methodology is similar to the cost-benefit analysis often used by government to evaluate public projects, and similar to the discounted cash flow method used by most private firms to evaluate capital investment proposals.

The second measure of economic viability is cost-of-service, the cost per unit (here the MMBtu) of delivering Alaskan natural gas to various markets in the lower 48 states. The principal difference between the NNEB and cost-of-service measures lies in the treatment of United States taxes. Those taxes are excluded from the NNEB calculus, but included in cost-of-service. (Foreign taxes are included in both). NNEB counts social costs only, while cost-of-service measures the private costs (exclusive of the field cost of gas) ultimately incurred by gas consumers. Each has its place in comparative analysis.

B. Defining the "Benefits" in NNEB

NNEB is defined as the present value of the benefits of a project less the present value of the costs of the project. The principal benefit is the value of the gas. The Department of the Interior (DOI) studied NNEB using a city-gate value (in constant 1975 dollars) ranging from $2.53/MMBtu in the early 1980's to $2.70 by the year 2000, based on a $12 per barrel price of oil. 1/

1/ Alaskan Natural Gas Transportation System, A Report to the Congress, Pursuant to P.. 93-153, DOI December 1975; p. 65. Note that $12/bbl of crude equates to $2.14 per MMBtu; thus, DOI and others all assume gas has value in excess of nominal Btu value.

Staff used slightly different methodology but developed similar values. Both Arctic and El Paso used the average DOI value of $2.62 in their NNEB calculations. 2 / We find a constant value of $2.62 adequate for these purposes, but if recent projections of world-wide hydrocarbon shortage within a decade materialize, our analysis understates the benefits of all three systems.

Various parties argued that the calculation should include other "benefits", such as maintenance of Canadian gas exports, reduced requirements for an oil storage program, and multiplier effects in employment. We reject the first contention because it is unlikely that the Canadian Government would set an export price much below the city gate value of the gas, even if Arctic's system were to make more Canadian gas available for export.

We likewise reject as a benefit the cost savings from reduced oil storage requirements. Admittedly, there are benefits. The availability of Alaskan gas may reduce our necessary strategic oil reserves, and give us greater bargaining power in world energy markets. Also, Alaskan gas supplies add important diversity to the Nation's portfolio of energy supplies. But, these benefits are too elusive to quantify accurately for a cost-benefit analysis. (The same is true of the costs of the environmental impact of each system.) Each of the systems would reduce dependence on oil approximately equally, so non-inclusion of this consideration penalizes no applicant.

Finally, El Paso argues that investment expenditures create jobs and income which multiply through the economy. Since El Paso spends more in the United States than do the other applicants, they contend that this "multiplier-employment" benefit will be far greater for their system. One of their witnesses estimated that the El Paso system would ultimately result in 749,000 man-years of United States employment, whereas Arctic Gas would provide only 250,000 man years. 3 /

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2 / See AA-127 and EP-275. Alcan provided no NNEB calculations.

3 / Initial Brief of El Paso Alaska on Net National Economic Benefit, p. 3.

The other applicants and Staff opposed inclusion of this benefit, stating that other private capital expenditures, or monetary and fiscal stimulation, could provide the same effect by El Paso's expenditures. While this argument is correct in theory, the government may not apply a comparable stimulus, in spite of high projected unemployment. Investment in capital equipment is one of the best methods to reduce unemployment. Thus, we find that some weight should be given to this factor and the El Paso project must be credited with an advantage. Furthermore, the diverse components of the El Paso system would spread its employment-multiplier impact more widely across the American economy than the other applicants.

C. The Costs in NNEB

The first major cost to consider is the incremental field cost of gas. This is basically the expense of gathering and conditioning gas for delivery since the gas is being produced in conjunction with oil that would be produced in any event. Some liquids must be stripped from the gas for hydrocarbon dew-point control. These would be used for fuel or transported by the oil line. The producers' operating agreement indicates that no oil production will be foregone if prudent gas production and water injection plans are followed. 4/ Exxon estimated the 1975 dollar costs of gas gathering and conditioning facilities at $1.836 billion. 5/ Spread over a four-year construction period, the approximate annual outlays would be:

Year	Outlay ($ millions)
1	$ 200
2	344
3	400
4	500
Subtotal	$ 1,444
AFUDC @15%	392
Total --	$ 1,836

4/ Prudhoe Bay Unit Agreement, March 29, 1977, Exhibit E, p.E-2. The producers point out that operations are subject to change with field experience. DOI's study, op. cit., supra, based its field cost in part on decreased oil production if gas is sold. There now appears to be no basis for that approach.

5/ T. 122/19,497.

Related operating and maintenance expenses other than fuel are estimated at $8 million per year. Fuel expenses are not explicitly included in the NNEB, but are reflected in lower volumes of delivered gas. The conditioning plant is assumed to be completed six months before deliveries begin to the lower 48, to allow time for testing.

The second major cost is construction of the transportation system itself. The third cost is the annual operating and maintenance expense of the system. Depreciation charges are excluded since they are not a real cost at that time. These cost components, along with minor working capital requirements, are depicted in Exhibits IV-1 through IV-3 for each of the systems. 6 /

Finally, there are the costs associated with taxes. United States income taxes are excluded on the grounds they are transfer payments rather than true resource costs. 7 /

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6 / Cost estimates for each of the systems have changed from time-to-time as system design modifications are made and engineering estimates altered. The costs reported here are consistent with those reported in Chapter VIII and are believed to be the most recent estimates made by each of the applicants. The one exception is that of El Paso's "Other Taxes." In their April 14, 1977, submission to the Commission, as well as in some earlier cost-of-service calculations, they assumed other taxes to be a fixed proportion of gross plant. We believe a better assumption is to relate other taxes to net plant, which results in a reduced tax burden over time. We consequently adopted Arctic's representation of El Paso's Other U. S. Taxes, as reported in Exhibit AA-127, after verifying that the initial year's taxes were consistent with El Paso's most recent filings.

7 / Arctic Gas argued repeatedly throughout the development of their case that United States taxes should be treated as a cost. We, like Staff, the other applicants, and Judge Litt, find their arguments that United States tax payments are a proxy for United States government service rendered, "externalities," and the dislocation costs of income redistribution wholly without support. See I.D. 334-335.

EXHIBIT IV - 1

ARCTIC NNEB COMPONENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
								CANADIAN TAXES	
YEAR	DELIVERED GAS (TRILLIONS BTU'S)	FIELD GATHERING & CONDITIONING ($MILLION)	FIELD G & C O & M ($MILLION)	TRANSPORT FACILITIES ($MILLION)	WORKING CAPITAL ($MILLION)	O & M ($MILLION)	U. S. OTHER TAXES ($MILLION)	OTHER ($MILLION)	INCOME ($MILLION)
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	18.2	0.0	0.0	0.0	0.0	0.0
1979	0.0	200.0	0.0	623.7	0.0	0.0	0.0	0.0	0.0
1980	0.0	344.0	0.0	1345.5	0.0	0.0	0.0	0.0	0.0
1981	0.0	400.0	0.0	1921.4	0.0	0.0	0.0	0.0	0.0
1982	0.0	500.0	0.0	1208.5	9.7	0.0	0.0	0.0	0.0
1983	471.1	0.0	4.0	407.2	8.4	42.5	24.3	0.5	0.0
1984	942.2	0.0	8.0	0.1	8.9	61.7	48.0	12.3	0.0
1985	942.2	0.0	8.0	8.7	0.7	60.8	46.1	13.0	0.0
1986	942.2	0.0	8.0	3.4	-0.1	59.8	44.3	13.2	56.4
1987	942.2	0.0	8.0	0.1	0.1	58.8	42.5	13.5	213.1
1988	942.2	0.0	8.0	6.2	-0.1	57.9	40.5	13.8	233.0
1989	942.2	0.0	8.0	3.7	0.0	57.1	38.7	13.9	254.0
1990	942.2	0.0	8.0	0.9	0.1	56.4	36.9	14.2	268.0
1991	942.2	0.0	8.0	22.7	-0.1	57.1	34.9	14.4	265.7
1992	942.2	0.0	8.0	18.4	-0.1	56.6	33.3	14.7	262.3
1993	942.2	0.0	8.0	17.7	0.4	56.5	31.7	14.9	257.7
1994	942.2	0.0	8.0	14.1	0.4	56.7	30.5	15.2	256.5
1995	942.2	0.0	8.0	0.0	0.4	56.8	29.5	15.5	255.4
1996	942.2	0.0	8.0	0.0	0.4	57.0	27.4	15.7	254.5
1997	942.2	0.0	8.0	0.0	0.0	57.0	25.3	16.0	254.2
1998	942.2	0.0	8.0	0.0	0.0	57.0	23.6	16.3	253.5
1999	942.2	0.0	8.0	0.0	0.0	57.0	21.2	16.6	252.9
2000	942.2	0.0	8.0	0.0	0.0	57.0	19.1	16.9	252.5
2001	942.2	0.0	8.0	0.0	0.0	57.0	17.0	17.2	252.2
2002	942.2	0.0	8.0	0.0	0.0	57.0	14.9	18.7	252.1
2003	942.2	0.0	8.0	0.0	0.0	57.0	12.9	19.1	252.9
2004	942.2	0.0	8.0	0.0	0.0	57.0	10.8	19.4	250.4
2005	942.2	0.0	8.0	0.0	0.0	57.0	9.0	19.8	232.4
2006	942.2	0.0	8.0	0.0	0.0	57.0	7.2	20.1	220.4
2007	942.2	0.0	8.0	0.0	0.0	57.0	5.4	20.5	205.0
TOTAL	23083.9	1444.0	196.0	5620.5	29.1	1422.7	675.0	385.4	5255.1

Prudhoe Bay Flow Rate: 2.4 Bcfd @ 1148 Btu beginning 7/1/83.
Total Energy Input Through 2007: 24,638 Trillion Btus.
Fuel Consumption: 6.31%.

Sources. Columns (3) and (4): See text.
Column (5): See Chapter VIII.
Columns (6), (8), (9), and (10): Arctic Gas Cost of Service, 4/15/77.
Column (7): FPC Staff, based upon Arctic's cost of service computer model.

All 1975 dollars except Columns (8), (9), and (10) which are nominal dollars.

EXHIBIT IV - 2

EL PASO NNEB COMPONENTS

(1) YEAR	(2) DELIVERED GAS (TRILLIONS BTU'S)	(3) FIELD GATHERING & CONDITIONING ($MILLION)	(4) FIELD G & C O & M ($MILLION)	(5) TRANSPORT FACILITIES ($MILLION)	(6) WORKING CAPITAL ($MILLION)	(7) O & M ($MILLION)	(8) U. S. OTHER TAXES ($MILLION)
1977	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978	0.0	0.0	0.0	35.6	0.0	0.0	0.0
1979	0.0	200.0	0.0	139.9	0.0	0.0	0.0
1980	0.0	344.0	0.0	1629.2	0.0	0.0	0.0
1981	0.0	400.0	0.0	2081.5	0.0	0.0	0.0
1982	0.0	500.0	0.0	1361.5	0.0	0.0	0.0
1983	433.9	0.0	4.0	339.8	55.4	86.4	41.7
1984	867.8	0.0	8.0	0.0	7.7	172.9	83.4
1985	867.8	0.0	8.0	0.0	0.0	172.9	80.1
1986	867.8	0.0	8.0	0.0	0.0	172.9	76.9
1987	867.8	0.0	8.0	0.0	0.0	172.9	73.8
1988	867.8	0.0	8.0	0.0	0.0	172.9	70.9
1989	867.8	0.0	8.0	0.0	0.0	172.9	68.1
1990	867.8	0.0	8.0	0.0	0.0	172.9	65.3
1991	867.8	0.0	8.0	0.0	0.0	172.9	62.7
1992	867.8	0.0	8.0	0.0	0.0	172.9	60.2
1993	867.8	0.0	8.0	0.0	0.0	172.9	57.8
1994	867.8	0.0	8.0	0.0	0.0	172.9	55.5
1995	867.8	0.0	8.0	0.0	0.0	172.9	53.3
1996	867.8	0.0	8.0	0.0	0.0	172.9	51.1
1997	867.8	0.0	8.0	0.0	0.0	172.9	49.1
1998	867.8	0.0	8.0	0.0	0.0	172.9	47.1
1999	867.8	0.0	8.0	0.0	0.0	172.9	45.2
2000	867.8	0.0	8.0	0.0	0.0	172.9	43.4
2001	867.8	0.0	8.0	0.0	0.0	172.9	41.7
2002	867.8	0.0	8.0	0.0	0.0	172.9	40.0
2003	867.8	0.0	8.0	0.0	0.0	172.9	38.4
2004	867.8	0.0	8.0	0.0	0.0	172.9	36.9
2005	867.8	0.0	8.0	0.0	0.0	172.9	35.4
2006	867.8	0.0	8.0	0.0	0.0	172.9	34.0
2007	867.8	0.0	8.0	0.0	0.0	172.9	32.6
TOTAL	21261.1	1444.0	196.0	5587.5	63.1	4236.0	1344.6

Prudhoe Bay Flow Rate: 2.3614 Bcfd @ 1130 Btus beginning 7/1/83.
Total Energy Input Through 2007: 23,862 Trillion Btus.
Fuel Consumption: <u>10.90%</u>

Sources. Columns (3) and (4): See text.
Column (5): See Chapter VIII.
Column (6): AA-127, Schedule 6.
Column (7): EP-202, EP-228, EP-215, WL-46, EP-229, EP-265 and 4/13/77 data request response.
Column (8): AA-127. This does not agree with El Paso's 4/13/77 data request response which erroneously escalates "Other Taxes". Beginning figures in AA-127 are close to El Paso estimates contained in exhibits listed under Column (7) Sources; hence, AA-127 representation is adopted here.

All 1975 dollars.

EXHIBIT IV - 3

ALCAN NNEB COMPONENTS

(1) YEAR	(2) DELIVERED GAS (TRILLIONS BTU'S)	(3) FIELD GATHERING & CONDITIONING ($MILLION)	(4) FIELD G & C O & M ($MILLION)	(5) TRANSPORT FACILITIES ($MILLION)	(6) WORKING CAPITAL ($MILLION)	(7) O & M ($MILLION)	(8) U. S. OTHER TAXES ($MILLION)	(9) CANADIAN TAXES OTHER ($MILLION)	(10) INCOME ($MILLION)
1977	0.0	0.0	0.0	4.6	0.0	0.0	0.0	0.0	0.0
1978	0.0	200.0	0.0	57.2	0.0	0.0	0.0	0.0	0.0
1979	0.0	344.0	0.0	437.5	0.0	0.0	0.0	0.0	0.0
1980	0.0	400.0	0.0	1527.1	0.0	0.0	0.0	0.0	0.0
1981	0.0	500.0	0.0	2245.3	0.0	0.0	0.0	0.0	0.0
1982	321.4	0.0	3.0	1413.4	27.3	17.9	41.6	13.1	56.6
1983	933.5	0.0	8.0	3.2	12.4	53.8	98.4	27.2	109.9
1984	933.5	0.0	8.0	8.7	2.0	54.7	92.4	28.3	114.9
1985	933.5	0.0	8.0	3.4	0.5	55.6	87.7	29.5	120.2
1986	933.5	0.0	8.0	0.2	1.0	55.6	81.5	30.8	122.3
1987	933.5	0.0	8.0	6.1	0.7	55.6	77.7	32.0	125.3
1988	933.5	0.0	8.0	0.6	0.8	55.6	73.2	33.4	123.4
1989	933.5	0.0	8.0	1.0	0.8	55.6	68.8	34.8	119.9
1990	933.5	0.0	8.0	22.3	0.7	55.8	64.1	36.4	116.4
1991	933.5	0.0	8.0	18.4	0.7	56.0	60.0	37.5	111.8
1992	933.5	0.0	8.0	17.8	1.5	56.2	56.5	39.6	109.7
1993	933.5	0.0	8.0	14.1	1.5	56.2	53.2	41.3	106.6
1994	933.5	0.0	8.0	0.0	1.3	56.2	50.1	43.1	104.4
1995	933.5	0.0	8.0	0.0	1.5	56.2	46.3	45.1	101.6
1996	933.5	0.0	8.0	0.0	0.8	56.2	42.5	47.1	98.0
1997	933.5	0.0	8.0	0.0	0.8	56.2	39.4	49.3	94.6
1998	933.5	0.0	8.0	0.0	1.0	56.2	35.6	51.4	92.5
1999	933.5	0.0	8.0	0.0	1.1	56.2	32.3	53.8	83.9
2000	933.5	0.0	8.0	0.0	1.0	56.2	29.2	56.4	138.0
2001	933.5	0.0	8.0	0.0	1.1	56.2	25.8	58.9	128.8
2002	933.5	0.0	8.0	0.0	1.0	56.2	22.2	62.0	119.6
2003	933.5	0.0	8.0	0.0	0.0	56.2	18.7	64.9	110.3
2004	933.5	0.0	8.0	0.0	0.0	56.2	15.4	68.0	101.2
2005	933.5	0.0	8.0	0.0	0.0	56.2	12.1	71.4	92.4
2006	933.5	0.0	8.0	0.0	0.0	56.2	8.8	75.0	88.4
TOTAL	22725.4	1444.0	195.0	5780.9	59.5	1359.2	1233.5	1130.3	2690.7

Prudhoe Bay Flow Rate: 1.6 Bcfd @ 1138 Btus beginning 7/1/82 (3.1 TBtus to Fairbanks in 1982).
2.4 Bcfd @ 1138 Btus beginning 1/1/83 (12.4 TBtus in 1983 and 18.7 TBtus to Fairbanks in 1984 and thereafter).

Total Energy Input Through 2006: 24,258 Trillion Btus.
Fuel Consumption: 6.32%.

Sources. Columns (3) and (4): See text.
Column (5): See Chapter VIII.
Column (6): Alcan Project Cost of Service, 4/15/77; Arctic Gas Cost of Service Filing, 4/15/77 (for lower U.S. facilities); Canadian portion estimated.
Column (7): Alcan's Answer to Interrogatories, 4/8/77, pp. 362-373.
Columns (8), (9), and (10): Alcan's Project Cost of Service, 4/15/77.

All 1975 dollars except Columns (8), (9), and (10) which are nominal dollars.

Taxes other than income (*e.g.,* property taxes) are included on the grounds that they are a proxy for the costs of governmental services (*e.g.,* roads, health systems and schools for construction workers and employees) required as a result of a system's construction.

Canadian taxes, both income and other, were treated as a cost in the three basic NNEB studies on grounds that they represent real resource claims on the United States by Canadians. 8/ We will initially adopt that position here, but will later argue that an alternative formulation of NNEB costs is more reasonable. All relevant taxes are depicted in Exhibits IV-1 through IV-3.

D. Net National Economic Benefits

Prior to calculating the NNEB of each proposed system, certain adjustments were made:

1. Arctic's 2.25 Bcfd case was scaled-up to 2.4 Bcfd to be comparable to El Paso and Alcan, whose system design and data are based upon that level.

2. Alcan's construction schedule was extended 9 months, with an in-service date of July 1982. 9 / Arctic's and El Paso's scheduled in-service date of July 1, 1983, was maintained.

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8 / DOI, Arctic and Staff all include a factor in the Canadian tax calculation for subsequent United States taxes collected when the money is returned via expenditures to the United States. We ignore that adjustment here, thereby underestimating the Arctic and Alcan NNEB estimates slightly.

9 / See Chapter VIII for the rationale behind this adjustment

DOI, Arctic, El Paso and Staff, all used a 10 percent rate of discount in their NNEB calculations, based upon DOI's assessment that this figure approximated the real before-tax rate of return on private investment experienced in the United States economy in the past. We believe this rate to be too high for a real social rate of discount. 10/ Thus, while we present results at 10 percent, we also calculate the projects' NNEB at 6 percent which is probably more realistic. 11/

Exhibits IV-1, IV-2, and IV-3 present the cost-benefit data for each system. Column (2) of each chart represents the benefits (in Btu's not in dollars); columns (3) through (10) represent the costs. All the tax amounts as stated in Exhibits IV-1 and IV-3 for Arctic and Alcan were then deflated at 5 percent per annum prior to discounting. 12/

10/ The United States Water Resources Council currently requires that all planning of water and related land resource projects be done at a 6-3/8 rate of discount.

11/ Without discounting, the NNEB of Arctic, El Paso and Alcan are $45.45 billion, $42.83 billion and $45.64 billion, respectively.

12/ Arctic and Alcan both submitted cost of service calculations, including tax components, based upon a 5 percent rate of inflation. We report those data in Exhibits IV-1 and IV-3. El Paso's cost-of-service submission based upon a 5 percent inflation rate was in error in its tax calculation. Its United States Other Taxes are consequently based upon one of Arctic's representations of El Paso. The El Paso tax data in Exhibit IV-2 is deflated only to 1982 since the Arctic tax calculation was based upon a real 1975 dollar rate base.

Our results, as summarized in Exhibit IV-4, are as follows:

1. Alcan has the highest NNEB at either discount rate. Arctic's NNEB is slightly lower. El Paso's NNEB is 75 to 82 percent of Alcan's at the 10 and 6 percent discount rates, respectively.

2. El Paso's NNEB differs from that of the other two applicants for two main reasons: El Paso has significantly higher operating and maintenance costs, and it delivers significantly lower volumes of gas. El Paso consumes 10.9 percent of total fuel input in its transportation system while the others consume approximately 6.3 percent.

3. Even at the higher discount rate, El Paso's out-of-pocket costs for transportation could increase over 50 percent and its NNEB would still be positive. For Alcan, cost overruns could exceed 100 percent and its NNEB would still be positive; for Arctic the overrun limit would be 93 percent. At a six percent discount rate, the capacity to absorb cost overruns is even higher. For example, Alcan could have cost overruns of almost 250 percent before its NNEB would become negative.13/

Alcan's comparative advantage over Arctic occurs for two reasons, both of which are of questionable significance. First, since it appears that Alcan would deliver the gas to market one year earlier, the present value of the total volume of gas delivered will be greater even though the total delivered volumes are almost identical for the two systems. If we were to allow for some increase in the real value of the gas over time, a condition that might very well exist, the value of Alcan's earlier delivery would be reduced. Also, as expressed in Chapter VIII, there is good reason to believe Alcan's construction cost estimates may be somewhat low. Thus we cannot find Alcan superior to Arctic on NNEB grounds: Both, however, offer more net benefits than El Paso. 14/

13/ One must keep in mind that this is not the best measure of a project. Elsewhere, we have stated that we believe Alcan's filed costs are subject to upward adjustment.

14/ We have some concern regarding the specification of cost and benefits for the two joint United States-Canadian systems. In the analysis above, the outlays associated with Canadian construction costs were treated as outlays by the U.S. at the time of construction. Since, however, the Canadian construction

(Footnote continued on next page)

EXHIBIT IV - 4

Net National Economic Benefits
Cost Allocation Case
(Billions of 1975 dollars)

	Arctic		El Paso		Alcan	
	10%	6%	10%	6%	10%	6%
Value of Gas	12.601	22.059	11.606	20.317	13.508	22.890
less:						
Field Gathering & Conditioning	0.961	1.124	0.961	1.124	1.057	1.192
Field O & M	0.041	0.071	0.041	0.071	0.044	0.075
Transportation Facilities	3.682	4.329	3.653	4.304	3.820	4.478
Working Capital	0.015	0.019	0.034	0.043	0.028	0.036
System O & M	0.304	0.527	0.883	1.545	0.306	0.520
U.S. Other Taxes a/	0.090	0.139	0.238	0.373	0.198	0.292
Canadian Income Taxes b/	0.355	0.648	--	--	0.309	0.484
Canadian Other Taxes b/	0.031	0.053	--	--	0.094	0.157
NNEB	7.122	15.149	5.798	12.856	7.652	15.655

Note: Flow volumes are nearly equal:

Artic: 2.4 Bcfd
El Paso: 2.3614 Bcfd
Alcan: 2.4 Bcfd

All dollar flows assumed mid-year. Present value at 1/1/77.

a/ El Paso's Other U.S. Taxes were deflated to 1982 at 5% before discounting. See EP-231, p. 117.

b/ All taxes were deflated by 5% to 1975 before discounting.

E. Comparative Cost of Service

The record developed over the past two years contains a plethora of studies by all the applicants which project the unit cost of transporting the Alaskan gas to the lower 48 states for each of the proposed systems. 15/ The results of these studies were of marginal value because they were based on inconsistent input data in that some components were expressed in constant dollars while others were not.

14/ (Footnote continued from prior page)

is being undertaken by Canadian companies, Canada (not the U.S.) will make those outlays. The U.S. will reimburse Canada over time through the cost of service charges over the economic life of the project. Thus the initial specification is arguably erroneous.

We have developed an alternative NNEB specification which considered as separate cost items the U.S. costs for construction and other items (O&M, working capital and U.S. Other Taxes), and the entire Canadian cost of service tariff. The results were very comparable to our original table:

	NNEB (Billions of 1975 dollars)	
	Original Method	Alternate Method
10% Discount Rate		
Arctic	$ 7.122	$ 7.533
El Paso	5.798	5.798
Alcan	7.652	8.023
6% Discount Rate		
Arctic	15.149	14.940
El Paso	12.856	12.856
Alcan	15.655	15.674

The El Paso NNEB is the same under either case since it is an all U.S. system.

15/ Alcan includes deliveries to Fairbanks. El Paso did not put any Alaskan service into their application but could clearly do so.

Hence, on April 4, 1977, we requested the applicants to recompute their cost of service under a consistent set of assumptions. 16/ After a discussion session to work out details, 17/ each of the applicants complied with the request by April 15, 1977. The figures in Exhibit IV-5 are a summary of those responses and are the most current estimates of the transportation charges for delivering Alaskan natural gas to the lower 48 states expressed in 1975 dollars.

The results essentially are consistent with our NNEB findings. Arctic has the lowest cost, followed closely by Alcan. El Paso's costs are considerably higher. 18/ Alcan's statement of cost may be a few pennies low due to optimistic estimates of construction cost and scheduling, and El Paso's may be a few pennies too high because of their improper treatment of Other U.S. Taxes and their inclusion of some Texas facilities that might prove unnecessary. 19/ We nevertheless believe these comparative results to be sound. For example, even if Arctic's Alaskan construction were to require a full year longer than scheduled, with a direct cost overrun (before AFUDC) of 40 percent, their twenty-year cost of service would rise only to \$ .85 per MMBtu, comparable to Alcan and well below El Paso.

These costs of service indicate an important fact: all of the systems can deliver the Alaskan gas at a reasonable cost to the consumer. Even El Paso could deliver gas at an average price of less than \$2.10 per MMBtu, assuming a field price of \$1.00 per MMBtu. We have no doubt that the gas is worth much more than this. Even with extremely large cost overruns, there is insignificant marketability risk for this gas, even on an incremental basis. 20/

16/ Alaskan Natural Gas Transportation Systems Cost of Service Analysis Request, (T.44,809).

17/ T.44,965-44,990.

18/ Unlike the NNEB comparison at the 6 percent discount rate, where Arctic and Alcan are 18 and 22 percent higher than El Paso, respectively, here they are 30 and 28 percent lower compared to El Paso.

19/ See Chapter VIII.

20/ In Chapter XII we recommend rolled-in pricing partly on the grounds that there is no need to provide a market test for this gas to pass.

EXHIBIT IV-5

PROJECTED TRANSPORTATION COST
(Dollars per million Btu) a/

Delivery Points	Arctic	El Paso	Alcan
First Full Five Years			
East	$ 1.23	$ 1.71	$ 1.30
Midwest	1.19	1.66	1.28
West	1.07	1.28	1.15 b/
National	1.17	1.53	1.24
Second Full Five Years			
East	0.83	1.31	0.86
Midwest	0.81	1.27	0.85
West	0.81	0.96	0.81 b/
National	0.82	1.16	0.85
Full Twenty Years			
East	0.76	1.23	0.80
Midwest	0.74	1.19	0.79
West	0.76	0.91	0.74 b/
National	0.76	1.09	0.79

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a/ Expressed in 1975 dollars.
Prudhoe Bay Flow Rates: Arctic 2.25 Bcfd
El Paso 2.3614 Bcfd
Alcan 2.40 Bcfd
Includes fuel cost @ $1.00/MMBtu.

b/ San Francisco.

Sources: Applicants' response to Cost of Service Data Request, 4/15/77.

CHAPTER V

ENVIRONMENTAL IMPACTS

A. Introduction

Alaska has been described as the last great frontier of America. It is unique among the 50 states in many environmental and cultural aspects. Each proposed transportation route traverses particularly fragile Alaskan areas, which cannot recover quickly from untoward intrusion by man.

Unique areas in Canada and the United States would be affected by the transportation system and therefore must be considered in this report. These range from the pothole districts of the Dakotas to the shorelines of California, from scenic rivers in the midwest to historical sites along the Mississippi River. We must consider all environments affected by the proposals before us, and we have attempted to do so in our deliberations.

In this Chapter we identify the more significant environmental impacts from the hearing record and subsequent presentations. As noted by Judge Litt, "seldom has a decision-making body been favored with so substantial a body of salient information upon which to draw in reaching a decision." 1/

Environmental impact statements were required for all proposals both by the National Environmental Policy Act of 1970 (NEPA) and Section 5(c) of the Alaska Natural Gas Transportation Act of 1976 (ANGTA). Reports prepared subsequent to the Initial Decision supplement these statements. Copies of these documents are attached to this recommendation and are available from our Office of Public Information.

1/ I.D. 173.

The approach throughout these proceedings has been to assess the maximum environmental risks presented by the applications, and by selected alternatives. We are convinced that all requirements of NEPA have been satisfied and that there is sufficient information for an effective environmental assessment. 2/

We recognize that the Morton decision established that a "crystal ball" was not required when considering environmental effects of reasonable alternatives. 3/ Nevertheless, we tried to foresee possible outcomes in weighing alternatives. And it was these realistic environmental alternatives which we weighed against the applicants' proposals.

Our position on several significant threshold issues provides the rationale for our ultimate environmental conclusions.

B. Threshold Issues

1. Concurrent Delivery of Prudhoe Bay and Mackenzie Delta Gas

Several additional pipeline alignments have been suggested that could deliver both Prudhoe Bay and Mackenzie Delta Gas. Consideration of these would raise additional environmental issues to be weighed.

We are not convinced that Mackenzie Delta Gas must be considered for the primary environmental evaluation of the competing applications. The applications should be assessed as proposed. Subsequently, we weigh various other delivery schemes for bringing both Alaskan and Canadian gas to market concurrently.

2/ Kleppe v. Sierra Club, 44 U.S.L.W. 5104, 5110 fn. 21, June 28, 1976.

3/ Natural Resources Defense Council v. Morton, 458 F.2d 827 (D.C. Cir. 1972).

Two pipeline systems in Canada could accomplish this objective:

(1) Maple Leaf, which is an actual application by Foothills Pipeline to the National Energy Board of Canada (Exhibit V-3C) and,

(2) the Richards Island Lateral (Dempster Highway Route) which FPC staff proposed as the preferred means for connecting the Delta area to Alcan near Whitehouse, Yukon (Exhibit V-3D).

These are not substitutes for one or more of the proposals before us. They are additional systems which could transport a Mackenzie Delta gas supply. Our particular environmental comparisons are made in this context.

2. Arctic National Wildlife Range

The selection of the Arctic Gas system would require entry into the Arctic National Wildlife Range. This development would probably act as an important catalyst for expansion into areas adjacent to the Range, due to increasing energy demands. Investigations from the air and, to a limited extent, on the surface, indicate a strong potential of substantial oil and gas reserves in that area.

Any verified natural gas reserve could readily and economically be attached to the proposed Arctic Gas system. It is likely that the gas would contain substantial liquids or be associated with oil. These liquid hydrocarbons could be transported west to Prudhoe Bay and then into the Alyeska system. The presence of the Arctic Gas pipeline thus would not constitute an additional incentive to later development.

We do not believe, therefore, that a decision on crossing the Range now is an irrevocable choice between total development or no intrusion at all on the Range. We believe that the Range would continue to support its current wildlife species, provided that strict controls and superior mitigation techniques are employed by the builders of the pipeline.

3. Multiple-Use Corridors

In the early development of Alaskan lands, an attempt was made to preserve natural beauty by confining development to specific corridors. This concept was adhered to in building the Anchorage-Fairbanks Highway No. 3 and the parallel railroad system of 1923.

With the discovery of the vast oil reserves on the North Slope, Alaskan State Officials, Bureau of Land Management personnel, and the Secretary of the Interior agreed upon establishment of a narrow, North-South utilities corridor in order to limit access to Alaska's interior and to control development. Further restrictions limited river crossings, bridges, and road quality. The Alyeska oil pipeline was constructed in this corridor.

Subsequent exploration for oil identified significant natural gas resources. El Paso, and later Alcan, have proposed using portions of the North-South corridor to transport natural gas. Alcan intends to follow highway and other rights-of-way through Alaska and over much of the Canadian portion of their system. Arctic also will use the corridor concept in parts of its system in Canada and the lower 48 states.

The 1973 amendment of the Mineral Leasing Act endorses the common corridor approach:

> "In order to minimize adverse environmental impacts and the proliferation of separate rights-of-way across Federal land, the utilization of rights-of-way in common shall be required to the extent practical ..." 30 U.S.C. 185(p).

Congress has created a presumption that proliferation of separate rights-of-way is to be avoided, and that use of rights-of-way in common will minimize impacts. We too support this approach to the extent it is compatible with other environmental factors. However, we accept the cautionary note sounded by Staff witnesses that the "common corridor concept should be not used blindly...". 4/ Transportation facilities will not necessarily be innocuous merely because they are placed adjacent to existing transmission facilities. A decision can only be made after a review of the environmental impacts of current land use and whatever effects that pipeline construction and operation may have on those uses.

C. The Environmental Setting

1. Climate and Physical Features

One or more of the proposed gas transportation systems would pass through the following climatic zones (tundra, subarctic, highland climates, marine temperate, continental steppe and continental moist). The predominant zone is subarctic, followed by highland climate. Exhibit V-1 shows four environmental characteristics of particular importance to pipeline construction and operations along the routes proposed.

The Arctic is characterized by long, cold winters, where temperatures may drop to -60°F. Summer temperatures, however, can reach 75°F. Annual rainfall averages less than 10 inches along the coastal plans, and snow is found to a depth of seven feet in the Brooks Range (Exhibit V-1B). Winds blow most of the time and range from 15 to 60 mph. As the pipeline moves southward, the climate moderates. Thus, the continental moist climatic zone records a winter average temperature of about 26°F and a summer average temperature of about 76°F. Annual precipitation in this zone may run as high as 40 inches. The marine west coast from Alaska to California stabilizes temperature, but the effect of mountains and prevailing winds produce storms and unpredictable weather inland. The mountains also cause rain on the western slopes of the mountains, and drier conditions to the east (Exhibit V-1B).

4/ Commission Staff Brief on Exceptions, p. 42, March 1, 1977.

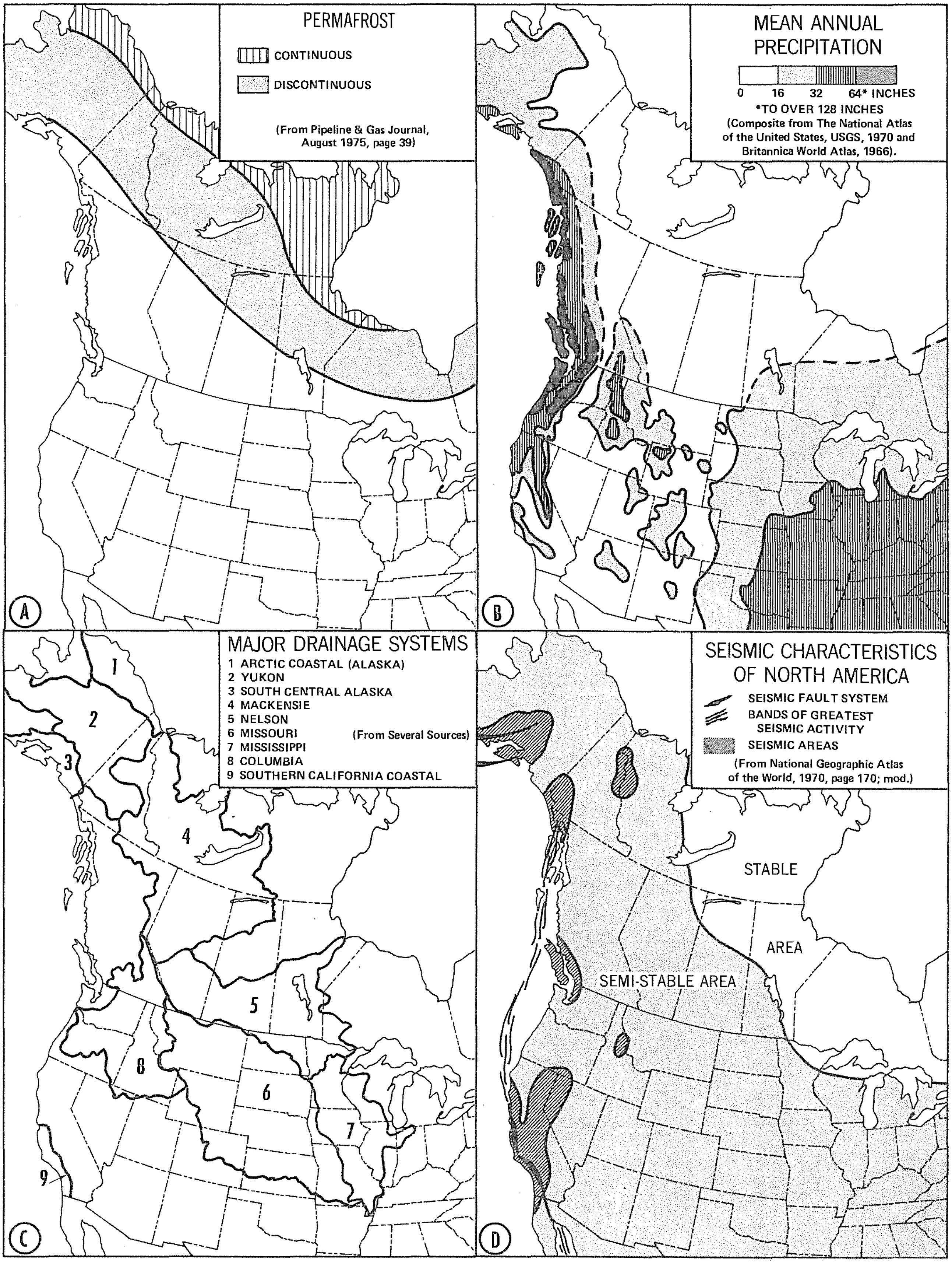

Exhibit V-I. Environmental Characteristics

With some noticeable exceptions, most of the proposed pipelines would cross relatively flat, low relief plains and valleys. In the interior plains, elevation increases and river valley provide the greatest relief. Steep terrain with slopes between 14 degrees and 35 degrees are usually confined to slump and thaw banks of river channels. Continental glaciation dominates the topography of the plains. The western part of Canada and the lower 48 States, however, is dominated by the Rocky Mountains, including such topographic features as the Brooks Range, Continental Range (including the Continental Divide), Rocky Mountain Trench, Columbia Mountains, Moyie River Valley and the Purcell Trench. In some of these areas, pipeline elevations would reach nearly 5,000 feet, such as Atigun Pass, where El Paso or Alcan would cross the Brooks Range.

Permafrost and tundra correlate in affecting construction and the environment (compare Exhibits V-1A and 2A). Permafrost exists where the ground remains frozen throughout the entire year. In northern latitudes permafrost can vary in depth from 10 feet to over 2,000 feet. Summer temperatures in these latitudes, however, can cause surface thaw to depths of 12 to 18 inches. This thawing and freezing leads to a gradual separation of soil and water, forming polygonal soil patterns typical of the tundra. Seasons of surface melt are short. Areas where there is permafrost and seasonal unfrozen ground mingle in so-called discontinuous permafrost zones (Exhibit V-1A). Severe cold winters, with limited snow accumulations, greatly expand the areas of frozen ground, while abnormally warm summers reduce the frozen area. Generally, thaw conditions in summer prevail for less than 90 days. Ground conditions and reactions in this zone also depend on soil types, textures, and water availability.

2. Natural Ecosystems

The areas affected by one or more of the routes encompass plant and animal communities representative of about half of the North American continent. Most of the area is either grassland, boreal forest, coastal forest, tundra and, to a lesser extent, desert shrub and chaparral (Exhibit V-2A). The environment supports a wide variety of

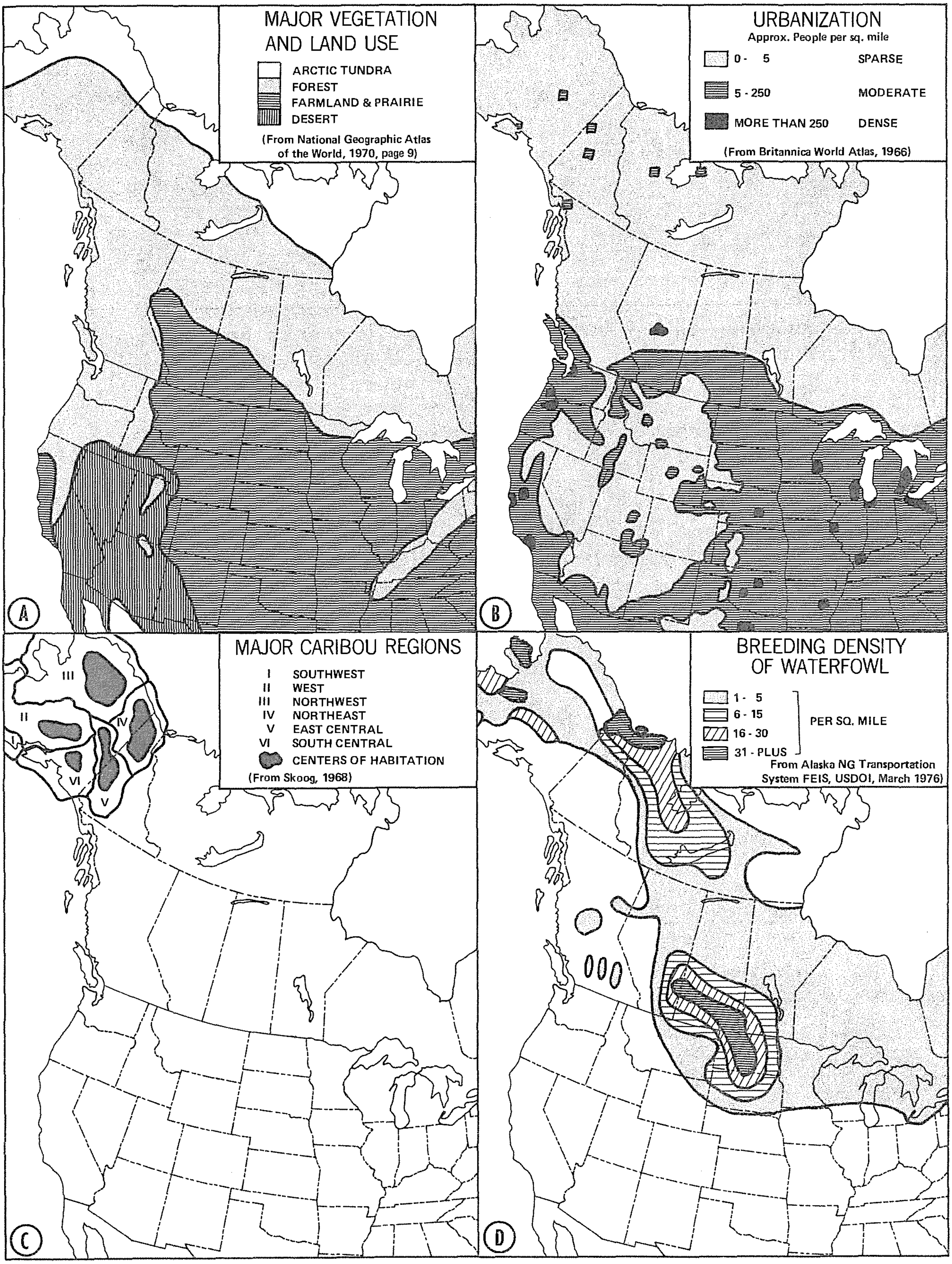

Exhibit V-2. Biotic Features.

wildlife. Marine mammals, such as whales, seals, and polar bears, are prevalent along the shorelines. Resident grazers of the tundra include caribou herds (Exhibit V-2C), musk ox, tundra vole, and lemmings. Other arctic wildlife species include moose, Dall sheep, wolves, foxes, grizzly bear, wolverine, coyote, and weasels. Grassland inhabitants include mule deer, whitetailed deer, pronghorn antelope and black bear, plus smaller species like badger, skunk, red fox, bobcat, rabbits, jack rabbits, ground squirrels, gophers and microtine rodents.

Two of the most prolific bird breeding and nesting areas in North America are near the pipeline routes: (1) Mackenzie Delta and River Valley and (2) Southern Saskatchewan and the Dakotas (Exhibit V-2D). About 139 species of birds from 31 families have been reported in the Mackenzie Delta. It is one of the largest summer breeding habitats in North America for waterfowl and is the hub of all four North American flyways.

Three major species of freshwater fish are prevalent (the arctic cisco, arctic char, and four-horn sculpin) plus six minor species. There is an abundance of both cold-water fish such as salmon, and warm-water fish such as bass, sunfish and catfish.

3. Land Use and Cultural Features

The undeveloped areas of Alaska and Canada serve chiefly as a wildlife habitat, with extensive areas of forest and grasslands. The grasslands, especially in the lower latitudes, support agriculture, as well as subsistence hunting, fishing and trapping, mineral exploration, recreation and some commercial fishing activity.

Most of the pipeline routes pass through sparsely populated areas, though El Paso and Alcan would approach Fairbanks. None of the routes would encounter other significant population concentrations until they terminate in the United States. Relatively denser populations are found in the farming regions of Southern British Columbia, Alberta, Saskatchewan, along the Northern Bordern route to Illinois, and throughout Washington, Oregon and northern California. (Exhibit V-2B.)

Most of the land in Alaska and Canada has been owned by government, so there has been little incentive for additional land use planning. However, recent oil and gas development in Alaska and the Alaska Native Claims Settlement Act, have stimulated the establishment of planning commissions, including the Joint Federal-State Land Use Planning Commission in Alaska.

In the lower 48 States, 90 percent of land is used for agriculture. In the midwestern States, croplands and pastures are most important, while farther west, grazing and forest activity increases. There is some mineral extraction. Land use planning is more associated with urban areas and only recently has formal rural planning activity started.

Historical, archeological or architectural sites which may be encountered by the proposed pipelines represent a broad spectrum of human activity in North America. The pipelines could affect archeological remains of such diverse cultures as the Arctic Eskimo, interior valley California Indians, and the mound builders of the Mississippi Valley. Similarly, sites of man's earliest occupation in North American are also found, along with the remanents of the Oregon Trail and other more recent historic structures.

4. Earthquake Conditions

The record of earthquake activity in Alaska is too short to permit a detailed assessment of future seismic risk. Earthquakes can be expected to occur during the period when natural gas is projected for transport out of Alaska. They could range from barely perceptible shakes to destructive quakes of 8.5 Richter magnitude.

An analysis of historic earthquake data indicates three areas of concentration in the Alaskan and Northwestern Canada regions (Exhibit V-1D). The largest grouping extends from offshore of Anchorage to north of Fairbanks. Another concentration occurs south of the Mackenzie Delta along the eastern Yukon border. The third is confined to the coastal area, south of Whitehorse. Given this distribution, it is clear that each proposed system is susceptible to earthquake damage.

In the southern portions of Alberta and Saskatchewan, as well as the northern border states, there is much greater stability. Epicenters are infrequent and of lesser magnitude.

The California sites for El Paso's LNG terminals is also an area of high seismic risk. Although the major facilities have been located at points of relative stability in the past, the distribution pipelines cross known faults and would have to be designed to protect the integrity of the system.

D. Route-Specific Features

1. Arctic Gas

a. Primary Route

The Arctic Gas proposal calls for 4,504 miles of pipeline in four major segments: (1) Alaskan Arctic, (2) Canadian Arctic, (3) Northern Border, and (4) Pacific Gas Transmission. (Exhibit V-3A).

Alaskan Arctic would construct 195 miles of 48-inch pipeline from Prudhoe Bay through the Arctic National Wildlife Range to the Alaska-Canada border. This is an area of low relief permafrost and grassland which supports herds of calving caribou (Exhibit V-2C). Until the discovery of oil, there was practically no human activity in this portion of the Arctic Coastal Plain, except for small native and government settlements along the coastline. (Exhibit V-2B).

Canadian Arctic would construct 2,297 miles of 48-inch pipeline from the Alaska-Canada border to the Canada-U.S. border. From the Alaska border the pipeline would continue southeasterly on the Coastal Plain for about 260 miles, crossing the Mackenzie River and reaching Travaillant Lake Junction, where it would receive gas from the Mackenzie Delta.

The Arctic pipeline uses the same coastal plain and Mackenzie River Valley route that early man used in his migration into North America from Asia. This suggests that Arctic would potentially encounter archaelogical sites.

The route moves southward along the east side of the Mackenzie River Valley, passing between the Norman Range and the River, then enters a large swamp area near the confluence of the Laird and Mackenzie Rivers. All of this area supports large populations of migratory waterfowl as shown in Exhibit V-2D. The Mackenzie River is crossed here, after which the elevation increases from 500 feet to 1,800 feet moving through swamp, lake, and hill country.

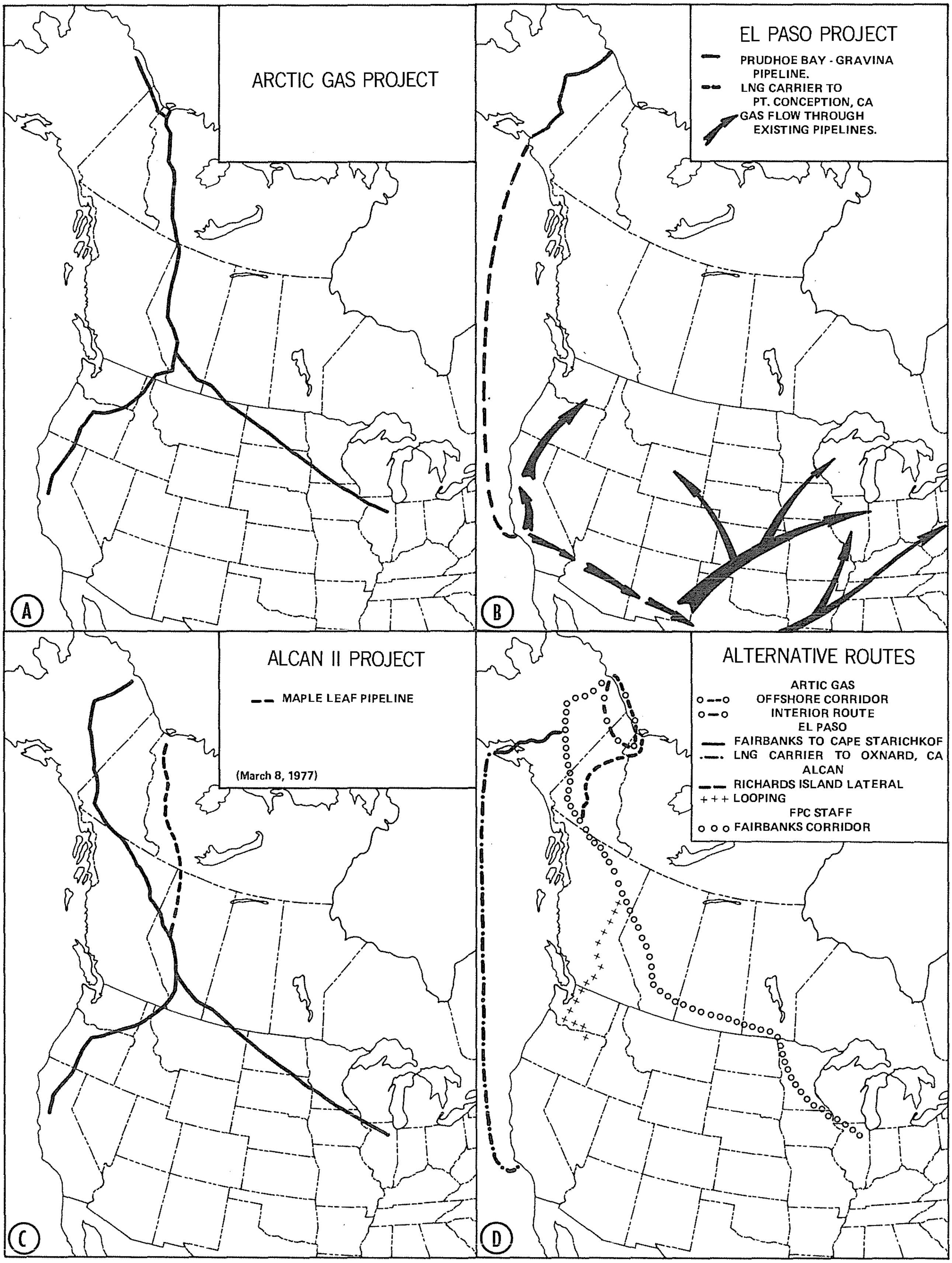

Exhibit V-3. Proposed Alaska NG Transportation Systems.

Several rivers with steep shorelines, such as the Peace and Smoky Rivers, are crossed in the Interior Plains.

In Alberta, the route crosses plains, rivers and sand hills until reaching Caroline Junction at 3,500 feet. Here the route splits into an east leg and a west leg. The east leg route generally drops to about 2,400 feet at the Saskatchewan River, and passes through sand hills until it reaches Monchy, Saskatchewan at the U.S. border. The west leg from Caroline Junction rises to about 6,000 feet through the Rocky Mountains and then descends to about 2,500 feet in the vicinity of the Moyie River and the U.S. border at Idaho.

Northern Border would construct 1,138 miles of 42-inch pipeline through Montana, the Dakotas, Minnesota, Iowa and terminate near Chicago. From an initial altitude of 2,650 feet, the route gradually descends to 460 feet elevation where it crosses the Illinois River. Basically, it passes within the end moraine areas of receding glacial activity. This is through the pothole sections of Montana and the Dakotas, noted as important bird breeding and nesting areas. (Exhibit V-2D). It also passes through a prominent saddle of the Killdeer Mountains west of Bismarck, North Dakota. The route crosses several main hydrological features, including Frenchman Creek (Montana), Little Missouri River (SD), the Wapsipinicon River (Iowa) and the Mississippi River (Iowa-Illinois).

Pacific Gas Transmission and Pacific Gas and Electric would construct 874 miles of 36-inch pipeline loop from the Idaho-Canada border through Idaho, Washington, Oregon and California, terminating near San Francisco. From Kingsgate, Canada, the route enters the U.S. by the narrow Moyie River Valley which averages 2,500 feet elevation. The route then enters the Purcell Trench and crosses Kootenai River in a two-mile wide valley. From there the route is in the flat Rathdrum Prairie near the Spokane River, crosses the Snake River and continues through flood plains of the Columbia River Valley before entering the steep John Day River

Canyon. The terrain is quite rugged until the flat alluvial valley of Crooked River. In California, the route enters the Modoc Plateau of rolling hills (3,400-4,600 feet elevation), and crosses the 800 foot deep canyon of the North Fork Bear Creek (1,900 elevation) before dropping to the Sacramento Valley near Red Bluff, California. The Sacramento Valley is characterized as rolling foothills, with alluvial fans.

1. El Paso

a. Alaskan Pipeline

The pipeline proposed by El Paso generally parallels the existing Alyeska oil line for a distance of 767 miles (Exhibit V-3B). For nearly 85 percent of this distance, the pipeline separation would be less than 3,000 feet. All existing facilities would be used to the extent possible.

The pipeline starts at the Prudhoe Bay field on the coast of the Arctic Ocean, and follows the existing utility corridor southward across the Arctic Coastal Plain. This is a flat area of deep-seated permafrost characterized in the summer by marshy grasslands and very poor drainage. The plain is interrupted occasionally by braided drainage from the foothills slope of the east-west trending Brooks Range. (Exhibits V-1A, C). The tundra here supports herds of caribou, moose, musk, oxen, several large carnivores, Dall sheep and numerous shore and waterbirds. (Exhibit V-2A)

Farther south, the route climbs abruptly, crossing the coalesced alluvial fans of the North Slope foothills. The soil here becomes coarse and rocky, with massive subsurface ice accumulations.

This entire area is dominated by the Brooks Range, a broad bank of glaciated mountains. The proposed gas line will cross through the narrow Atigun Pass in close proximity to the existing Alyeska oil line. This is the highest point in the proposed system, an elevation of 4,750 feet.

Glaciation has removed the soil along this portion of the route, and construction will be hampered by steep slopes, rock excavation, and general space limitations.

The descent southward from the pass follows the broad valley of the Upper Chandalar, the Dietrich, and the Middle Fork Koyukuk Rivers. Landslides, soil movement, and numerous freeze-thaw cycles are common.

Several rugged discontinuous lowland ridges border the southern front of the Brooks Range. The route crosses this terrain at right angles. Intense glaciation has produced rock basins, deep narrow canyons, and depositional moraines.

From the highland region to Delta Junction, a distance of over 200 miles, the route traverses the major drainage basin of the Yukon-Tanana Rivers (Exhibit V-1C). With the exception of the Rampart Trough, a deeply incised depression which confines the Yukon River, the drainage area has a rounded, gently undulating topography. Near the Tanana River crossing at Delta Junction, the alignment leaves the valley flood plains and crosses a diversified surface of glacial outwash and terminal moraines. Thaw lakes and thermokarsting abound in the fine-grained soils.

Proceeding southward, the line passes east of the rugged central portion of the Alaska Range. Although Mount McKinley, some 200 miles to the west, dominates, rising to 20,269 feet, most of the peaks rise from 6,000 to 9,500 feet. In the pipeline area, the range is characterized by swift-flowing streams, valley glaciers, and massive rock exposures. Isabel Pass, a high point along the existing corridor, is crossed at an elevation of 3,200 feet.

Beyond the Pass, glacial activity has sculptured the landscape across the Gulkana upland to the Copper River lowlands. The proposed route extends along the western edge of the Copper River basin. The Gulkana, Tazlina, and Klutina, major tributary streams, will be crossed along the alluvial flood plain.

South of the Brooks Range, extending to the southern coast, the vegetation is interior forest or taiga, comprised of spruce-hardwoods and treeless bogs. Along the coast there is a transition to Sitka spruce-hemlock forests. Wildlife and bird populations consist of moose, bear grizzlies, wolves, several species of furbearers, and 161 species of birds.

The final reach of the El Paso alignment traverses the Chugach Mountains, an extremely rugged coastal range with peaks ranging to 13,000 feet. Alpine topography prevails, with sharp peaks and ridges and glaciated valleys. The coastal front is deeply indented by fjords extending from the Prince William Sound.

The proposed route then rises out of the Copper Basin along the Richardson Highway through Thompson Pass. Moderate to steep slopes border the alignment and construction would be hampered by talus slopes, landslide potential and extensive timber clearing. The 33 mile right-of-way through the Chugach National Forest would require clearing an estimated 6 million board feet. The Chugach National Forest is "wilderness in fact" (I.D. 238), although, like the Wildlife Range, it is not designated "wilderness" under the Wilderness Preservation Act.

The route descends along the drainage valleys to the Gravina River flood plains and then to Gravina Point on the Prince William Sound.

b. <u>Gravina Point Terminal</u>

The Gravina Point LNG facility would occupy about 500 acres of a densely forested, gently sloping, piedmont ridge. Although foundation investigations have not been undertaken, soil and rock exposures suggest that the entire facility can be built on bedrock. Offshore soundings support the designs for a suitable deep water harbor.

Important wildlife found around Prince William Sound include brown and black bear, sea otter, mountain goat and Sitka black-tailed deer which winter on Gravina Point. There is a high concentration of bald eagle nesting in the Gravina Point area.

Prince William Sound provides the main ports for Gulf of Alaska commercial fishing fleets, which harvest a variety of fish as well as shrimp and crab.

El Paso, as well as Alcan, would cross areas of identified high potential archeological site concentrations. Along the Alyeska corridor, this would include the Atigun Pass and its approaches. In the pass itself, 97 sites have been discovered ranging in occupation date from 12,000 B.C. to recent times.

Farther south, El Paso will pass another archeologically significant area south of Delta Junction along the Delta, Gulkana and Copper Rivers. Here the pipeline would pass near the Tangle Lakes Archeological District, the most densely concentrated area of sites in Alaska.

Outside the Alyeska corridor, Alcan traverses other archeologically sensitive areas, including the Healey Lake site, and the area between the Canadian border and Teslin, Yukon.

The route through Saskatchewan shared by Alcan and Arctic also includes dense concentrations of sites.

c. LNG Tanker Transport

From the Gravina Point LNG facility, oceangoing cryogenic tankers would transport 165,000 M^3 of the LNG cargo per ship to a receiving and regasification plant on the California coast. A fleet of 8 cryogenic LNG tankers is proposed to maintain constant transport between Alaska and California. A one-way voyage would require 4 1/2 days at the average speed of 18.5 knots.

d. Point Conception Terminal and Arvin-Cajon Pipeline

Point Conception would be the California coastal terminus for receiving LNG deliveries. The plant facilities would be constructed on a 227-acre site, with a 4,600-foot lonq marine trestle and twin berthing facilities.

The plant site would be situated on the coastal terrace in an area zoned for limited agriculture and cattle grazing. (Exhibit V-2A). The Santa Ynez Fault is the only major fault in the area and traverses the coastal range about 3.5 miles from the plant site (Exhibit V-1D). Bedrock exposures along the coast also insure a stability against seaward erosion. Vegetation consists of natural grasses with dispersed low shrubs. Larger trees, typically live oaks and junipers, are found along the intermittent drainages.

From the regasification facility, a pair of 42-inch pipelines would transport the natural gas to Arvin, California, a distance of 142.3 miles. A single 42-inch pipeline would also extend the system to a Pacific Gas and Electric line at Cajon, 108.9 miles to the south. These lines would extend inland from the coastal facility, traversing the Santa Ynez coastal mountain range. The coastal area is lightly developed, with agriculture, cattle grazing, and private homesites along the foothills. Away from the foothills, the line would traverse irregular topography covered by a dense brush, typical of the semi-arid region. Major fault crossings would require detailed design for safety and accessable repair. The decent into the central valley, follows the foothills and crosses several intermediate ridges, generally bordering agricultural lands.

The route in this area would require 3,400 acres in new right-of-way, substantially more than the Oxnard alternative. Four endangered species have a habitat in this area, the San Joaquin kit fox, the prairie falcon, the blunt-nosed leopard lizard, and the California Condor.

Twenty-seven archeological sites are known for the entire Point Conception area. There are also 40 known sites along the pipeline route, including the Cajon Quadrangle at the end of the route, containing 23 formally recorded sites. Several of these sites have recently been nominated to the National Register.

e. Cook Inlet Alternative

Commission Staff has recommended an alternative routing for the southern portion of the El Paso system which avoids crossing the Chugach National Forest and, places the LNG facility at Cape Starichkof (Exhibit V-3D).

At livengood, a location just north of Fairbanks, the alternative alignment would diverge south to Dunbar. From this point to the Cook Inlet near Anchorage the route would follow a nearly straight line of right-of-way of the Multi-Mode Utility Corridor. The Corridor is now used by the Fairbanks-Anchorage Highway No. 3 and the Alaskan Railroad. A number of villages are located along this route, as well as the site for the proposed new state capital.

The proposed route traverses the central portion of extremely rugged Alaskan Range, following the eastern boundary of Mount McKinley National Park. Steep slopes, rock and talus, as well as space limitations would hamper construction. The area south of Fairbanks has agricultural potential, while the Matanuska Valley north of Anchorage is the leading agricultural area of Alaska.

Seismic activity along this proposed alignment is know to be high and major faults with recorded activity cross the alignment (Exhibit V-1D).

From the foothills of the Alaskan Range to Cook Inlet, the alignment would basically follow the Susitna River flood plains, which experience glacial floods and scour.

A sixteen mile submarine crossing would span the Cook Inlet at the northern edge of the Kenai Peninsula. The pipeline would then go southward across broad terraces, now being farmed, and across part of the Kenai National Moose Range to a terminal site at Cape Starichkof, on the southwestern shore of the Kenai Peninsula. There is an active commercial fishery in the lower Cook Inlet, with Homer as a main port.

f. Oxnard Terminal and Quigley Station Pipeline Alternative

As an alternative to Point Conception, Commission Staff suggested a terminal at Oxnard, California, about 70 sea miles southeast. These sites are comparable in many respects and would require the same facilities (Exhibit V-3D). A 5,850-foot long trestle would be required for the simultaneous berthing of two cryogenic tankers.

The proposed Oxnard LNG terminal would be situated in an area zoned for long-range heavy industrial use. It is a flat area of low elevation. Seismic hazards would exist and must be considered in plant design (Exhibit V-1D).

From the regasification and storage facility at Oxnard, a pipeline would extend inland to Quigley Station, a distance of 169 miles. Over 96 percent of this proposed alignment would follow existing rights-of-way.

3. Alcan II

a. The 48" Alternative

The Alcan II 48-inch pipeline proposal would extend from Prudhoe Bay, follow the utility corridor through the Brooks Range, pass east of the City of Fairbanks, run adjacent to the Alaska Highway corridor into Canada, past Whitehorse, Yukon, through British Columbia and Alberta to Caroline Junction. South of Caroline Junction, the system would divide into an east and west leg, similar to the previously discussed Arctic Gas System (Exhibit V-3C).

For the first 539 miles from Prudhoe Bay, Alcan II would follow the utility corridor used by Alyeska Oil Pipeline and the proposed El Paso gas pipeline. Along this part of the route the environmental setting would be identical to that described earlier for El Paso. From Delta Junction, Alcan would proceed eastward along the Alaska Highway and Haines pipeline corridor 192 miles to the Canadian border. This route is through low lying country marked by low relief with a few areas of rolling hills and a patchwork of grasslands, shrubs and and forests.

In Canada the route generally parallels the Alaska highway across the Yukon and British Columbia, to Alberta. It cuts through the Yukon Plateau with its marchy valleys and rolling hills, and encounters bog-fens, alpine tundra, subalpine forest and boreal forests. Animal life is varied and abundant with moose, caribou, Dall sheep, elk, beaver, muskrat, and several varieties of bears found along the route. In Alberta, the pipeline would run southeasterly to Caroline Junction, along the existing AGTL system right-of-way. In Alberta the terrain alternates between well-drained upland plateaus and lowlands. The pipeline enters the plains region once it approaches Caroline Junction. This route passes mostly through subalpine and boreal forests, interspersed with open grasslands and agricultural lands.

In most respects, the Alcan II route is similar to the Fairbanks corridor route which environmental staff found to be environmentally preferable to the Arctic or El Paso under certain conditions.

At Caroline Junction, the Alcan pipeline system divides, with one route going to Monchy and on to Illinois, and the other to Kingsgate and California. (See Arctic discussion for a description of the environmental setting for these parts of the system.)

b. <u>Richards Island Lateral and Maple Leaf Pipeline</u>

The FPC staff proposed the 756 mile Richards Island lateral to connect the Mackenzie Delta gas supply to its Fairbanks alternative in the vicinity of Whitehorse, Yukon (Exhibit V-3D). The addition of this line makes Alcan comparable to Arctic from the standpoint of delivering both North Slope gas supplies. This route traverses permafrost zones (Exhibit V-1A) to the east of the Mackenzie Delta, crosses the Mackenzie River and runs the length of the Yukon Province to Whitehorse. After the river crossing, it moves through boreal forest lands, (Exhibit V-2A), the upper Yukon River drainage (Exhibit V-1C) and through a seismic zone (Exhibit V-1B). The route is intended to parallel the proposed Dempster Highway, about half of which is already constructed as the Whitehorse-Dawson Road.

The Maple Leaf line, shown in Exhibit V-3C, follows the same general alignment and environmental setting as parts of the Canadian Arctic line (compared with Exhibit V-3A).

E. Environmental Discussion

Construction and operation of any one of the three proposed natural gas transportation systems (Exhibit V-3) will inevitably cause some adverse environmental impact (I.D. 176). The important point is to identify these impacts and to evaluate their significance. We have emphasized the nature of the habitat, as defined by vegetation and animal life, because the extent of disruption and degradation of habitat is the key to evaluating the environmental impacts, and reaching decisions on realistic alternatives and palliatives.

1. The Arctic Tundra

The northernmost habitat is the most fragile, where the land slopes from an elevation of 250 feet down to the Beaufort Sea. This coastal plain of Northern Alaska is Arctic tundra (Exhibit V-1A). Wherever construction and operation of pipelines thaws ice-rich permafrost, differential subsidence, destructive drainage changes, massive soil sloughing, and serious damage to vegetation will result. The Arctic tundra is akin to a frigid desert, receiving an average of less than 16 inches of precipitation annually (Exhibit V-1B). Aridity limits the availability of water for construction of ice and snow roads and pads. If streams are used for water to make snow, they could go dry, thus harming the aquatic habitat.

Particular interest centers on the wilderness in the northeast corner of Alaska where 14,000 square miles have been set aside as the Arctic National Wildlife Range. The coastal plain in this area serves as the calving area for the porcupine caribou herd (see Exhibit V-2C).

Impacts on habitats in the permafrost area (Exhibit V-1A), due solely to pipeline construction and operation are potentially greatest from the Arctic Gas route (Exhibit V-3A) and least along the El Paso route (Exhibit V-3B). Construction of the Maple Leaf pipeline would increase the habitat impact of the Alcan proposal (Exhibit V-3C), in the discontinuous permafrost region (Exhibit V-1A), compared to Arctic Gas and El Paso.

Limited availability of water in permafrost areas likewise poses greater potential for habitat degradation from Alcan and Arctic Gas, than from El Paso.

Only the Arctic Gas route impinges upon the Arctic National Wildlife Range and the calving activity of the porcupine caribou herd. All three pipelines have the potential, however, for disrupting the interherd migration which is necessary for maintenance of the caribou population.

The Arctic coastal plain habitat is critical to the breeding and molting of hundreds of thousands of waterfowl and shorebirds (Exhibit V-2D). The foothills of the North Slope provide a good raptor habitat. Satisfactory measures can minimize any adverse impacts so that they will not seriously affect the bird population. 5/

The Arctic Wildlife Range also represents one of the few remaining examples of an almost completely untouched wilderness. The Brief on Exceptions of Sierra Club, *et al.*, presents an eloquent exposition of the value of this intangible, yet important, resource. 6/ As they state, "wilderness is valuable as a retreat and a source of spiritual renewal, a benefit easily downgraded in our secular and industrial age." 7/

The total preservation of that wilderness is an important value. Any trespass on the range must be counted as an adverse impact, and must be minimized as much as possible if a decision is made to construct the Arctic system.

2. Northern Forest

The bulk of the northern portions of the pipelines traverse the great northern forest (Exhibit V-2A), comprised mainly of upland spruce and hardwoods and stands of coastal

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5/ I.D. 220.

6/ pp. 40-46

7/ I.D. 45.

hemlock and spruce. The pipeline routes generally follow natural and man-made corridors which are often deforested. Discontinuous permafrost and limited precipitation are characteristic of the area, though wet and alpine tundra also exist.

The Chugach National Forest has high aesthetic value, in contrast to the Arctic tundra. 8/ Both forest and tundra will be adversely affected by the pipelines. Tundra, however, is the more fragile habitat.

3. The Prairie - Farmland Area

Measures can be applied in the prairie area (Exhibit V-2A) to diminish the environmental impact on the water fowl (Exhibit V-2D) which abound in the extensive pothole region in the central portion of the continent. Realignment of pipeline facilities can also decrease impact on the diminishing woodlands and scenic rivers, and decrease erosion at pipeline river crossings and in the badlands. 9/

4. Marine Fisheries

Abundant marine fisheries, both finfish and shellfish (including crabs), exist in the coastal waters of Alaska. A sea water cooling system at an LNG terminal in Price William Sound could produce an unacceptable impact on marine fisheries, particularly from heated water discharges. 10/

5. Native Populations

The impact of pipeline construction on small communities along all three routes is likely to be more significant in Alaska and Canada than in the lower 48. Native communities are situated along each route. The juxtaposition of native and non-native cultures during the construction phases could lead to social problems for those communities. This situation may be less acute along the Alyeska and highway corridors than in the more remote northern areas farther removed from modern influences.

8/ I.D. 191-192.

9/ I.D. 224-229.

10/ I.D. 241.

6. Cultural Resources

Three factors will ultimately determine the likelihood of significant impact on cultural resources: (1) the location of facilities in areas that may have supported prehistoric cultures; (2) the state of archeological knowledge along the particular route; and (3) the survey/salvage program proposed, its timing and implementation during construction.

El Paso and Alcan will benefit from the extensive surveys conducted by Alyeska along the corridor. However, once outside this corridor, the detail available diminishes. Arctic has done preliminary reconnaissance along its Canadian route and has identified areas of critical importance requiring special attention.

Cultural resource surveys in the initial phases of detailed project design would identify specific critical areas and form the basis for later salvage excavation efforts. A mitigation program similar to the "Terms and Conditions" discussed in Chapter XIII would greatly reduce the potential destruction of archeological and historical sites.

F. Geotechnic Factors With Environmental Aspects

The principal geotechnical problems faced by each of the proposed systems are discussed in Chapter VII, Geotechnical Issues and System Reliability, and Chapter VIII, Construction Costs and Scheduling. Here we discuss three related issues.

1. Construction in Permafrost Zones

The difficulties of construction in permafrost areas will be comparable for all applicants. Construction in continuous permafrost should be undertaken only in intervals when no thawing occurs. This timing will assure that excavated frozen materials remain frozen and are replaced in the trench as frozen backfill. There would then be no appreciable net change in soil moisture or moisture concentrations. There would also be no infiltration of moisture into the excavated trench. In this area of sensitive equilibrium, the removal of vegetation and excavation of soil would cause a significant change in the solar heat absorption by the soils. If this activity is scheduled during a warm summer, the construction will then encounter thaws, melt-water infiltration, trench sidewall sloughing, and net changes in soil moisture. Frost heave and ice wedge formation will be more prevalent and severe.

Most critical to construction in the permafrost area is the period following construction and prior to system operation. With vegetation removed and disturbed soil backfilled, thaw action can be deeper than normal with settlement, ponding, and associated imbalances. Additional research and testing are needed to develop methods of temperature control during this critical interval.

The new techniques proposed by Arctic to defeat frost heave, even if successful, introduce a different set of environmental impacts, which are now indeterminate.

2. Excavation Spoil

The trenching operation for the buried pipeline will yield about a cubic yard of excess material per foot of pipeline. A surcharge or berm on top of the backfilled trench would not be environmentally beneficial. It would interrupt local drainage, increase maintenance, and greatly increase local sedimentation. The problem of the disposal of this excess material still needs to be resolved.

3. Snow Roads and Work Pods

We have discussed the technical feasibility of snow roads in Chapter VIII. Here we simply note that they are essential for an environmentally-acceptable crossing of the North Slope in general and the Arctic National Wildlife Range in particular.

G. Environmental Summary

Judge Litt observed that the record before us "is literally awash with excellent material relating to every aspect of the environment." 11/ We begin (Exhibit V-4) with a structuring of the major characteristics of the various habitat categories. For example, along the proposed

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11/ I.D. 176.

EXHIBIT V-4: A MATRIX SUMMARIZING RELATIVE CRITICALITY OF KEY ENVIRONMENTAL CONSIDERATIONS IN RELATION TO FOUR MAJOR HABITAT CATEGORIES.

HABITAT CATEGORIES (Exh. V-2A)	ENVIRONMENTAL CHARACTERISTICS			
	Permafrost (Exh. V-1A)	Precipitation (Exh. V-1B)	Drainage * (Exh. V-1C)	Seismicity ** (Exh. V-1D)
1. Tundra	P	P	O/S	P/S
2. Forest	P/S	P	P	P/S
3. Prairie	O	P	S	O/S
4. Aquatic	P/S	P	P	P/S

	BIOTIC FEATURES				
	Vegetation (Exh. V-2A)	Natives (Exh. V-2B)	Wildlife (Exh. V-2C and 2D) Mammals	Birds	Fishes
1. Tundra	P	P	P	P	O/S
2. Forest	P	P/S	P	P	O/S
3. Prairie	P	O/S	S	P	O/S
4. Aquatic	P/S	P	S	P	P

P = Primary Relationship P/S = Either or Both

S = Secondary Relationship O/S = Either or Both

O = Little or No Consequence

* Includes impacts on hydrologic features. Areas of concern include channel erosion, icings, depletion of streamflow, and drainage disruptions.

** Considered in terms of potential impacts derived from destruction of pipeline facilities by seismic activity.

natural gas transportation routes, permafrost and precipitation are of primary concern in the tundra, whereas, drainage is probably of secondary or no importance, and seismicity (depending upon location) may be of primary or secondary significance. There is general agreement that permafrost, low precipitation, sparse vegetation, and the short growing season all stamp the tundra as the most fragile environment that will be encountered by any pipeline. In the Arctic National Wildlife Range and the Mackenzie Delta, the tundra is critical for calving of and breeding of caribou, waterfowl and shorebirds.

Exhibit V-5 provides a summary of the major environmental considerations. The major sensitive conditions are identified along each of the three proposed routes in Exhibits V-6, V-7 and V-8, and for the various alternatives (Exhibit V-9). If only transport of Alaskan gas is considered, we agree with Staff's conclusion that a project similar to the Alcan II 48-inch pipeline alternative, without either a "western leg" or the Maple Leaf Project, would constitute the most environmentally acceptable system to transport Prudhoe Bay gas to the contiguous United States. 12/

The major environmental advantages of Alcan II over the Arctic Gas proposal are listed below:

1. Existing multi-use corridors would be used to the maximum, meaning less development of rights-of-way in virgin or unimpacted areas.

2. The Arctic National Wildlife Range, similar areas in Canada, and related waterfowl breeding areas, would not be crossed.

3. Caribou calving grounds in Alaska and Canada would be avoided.

12/ Commission Staff report, April 8, 1977. Exhibit V-10 depicts the proposal though most environmentally acceptable by Staff.

EXHIBIT V — 5: SUMMARY OF ENVIRONMENTAL CONSIDERATIONS.

Key Habitats	Environmentally Sensitive Conditions Along Proposed Routes ARTIC GAS (Exh. V-6)	EL PASO (Exh. V-7)
1. Tundra	Fragile tundra; Alaska National Wildlife Range; prime waterfowl and shore-bird breeding area; calving ground of Porcupine caribou herd; limited water supply.	Fragile tundra; limited water supply.
2. Forest	MacKenzie River drainage; bird breeding area (B); seismic potential(S).	Yukon River drainage; barrier to interherd caribou migration: Chugach National Forest; seismic potential (S).
3. Prairie	Waterfowl breeding area (B); pothole terrain.	— — —
4. Aquatic	— — —	Brine and heated water discharge into marine fisheries area.

	ALCAN II (Exh.V—8)	ALTERNATIVE ROUTES (Exh. V-9)
1. Tundra	Fragile tundra; prime waterfowl breeding area; limited water supply.	
2. Forest	Yukon and MacKenzie River drainages; bird breeding area; barrier to interherd caribou migration; seismic potential (S).	((Each of the several alternative route segments (Exh. V-9) and the environmentally most acceptable route (Exh. V-10) have different impacts, as indicated)).
3. Prairie	Waterfowl breeing area (B); pothole terrain.	
4. Aquatic	— — —	

— — — = Not Applicable

In comparison with the El Paso proposal, the Alcan II route avoids the environmental impacts of:

1. Construction of two LNG terminals in high seismic risk areas, and impacts on marine and wildlife resources in Prince William Sound.

2. Construction of a pipeline through the Chugach National Forest.

We share Judge Litt's conclusion that each of the proposed systems can be built in an environmentally acceptable manner. The proposed routes do traverse regions that are particularly sensitive to environmental impacts. But the record has shown that the environmental damage can be minimized without serious, long-term consequences. We, of course, expect that the responsible Federal, state, and local licensing agencies will exercise their authority to require appropriate measures.

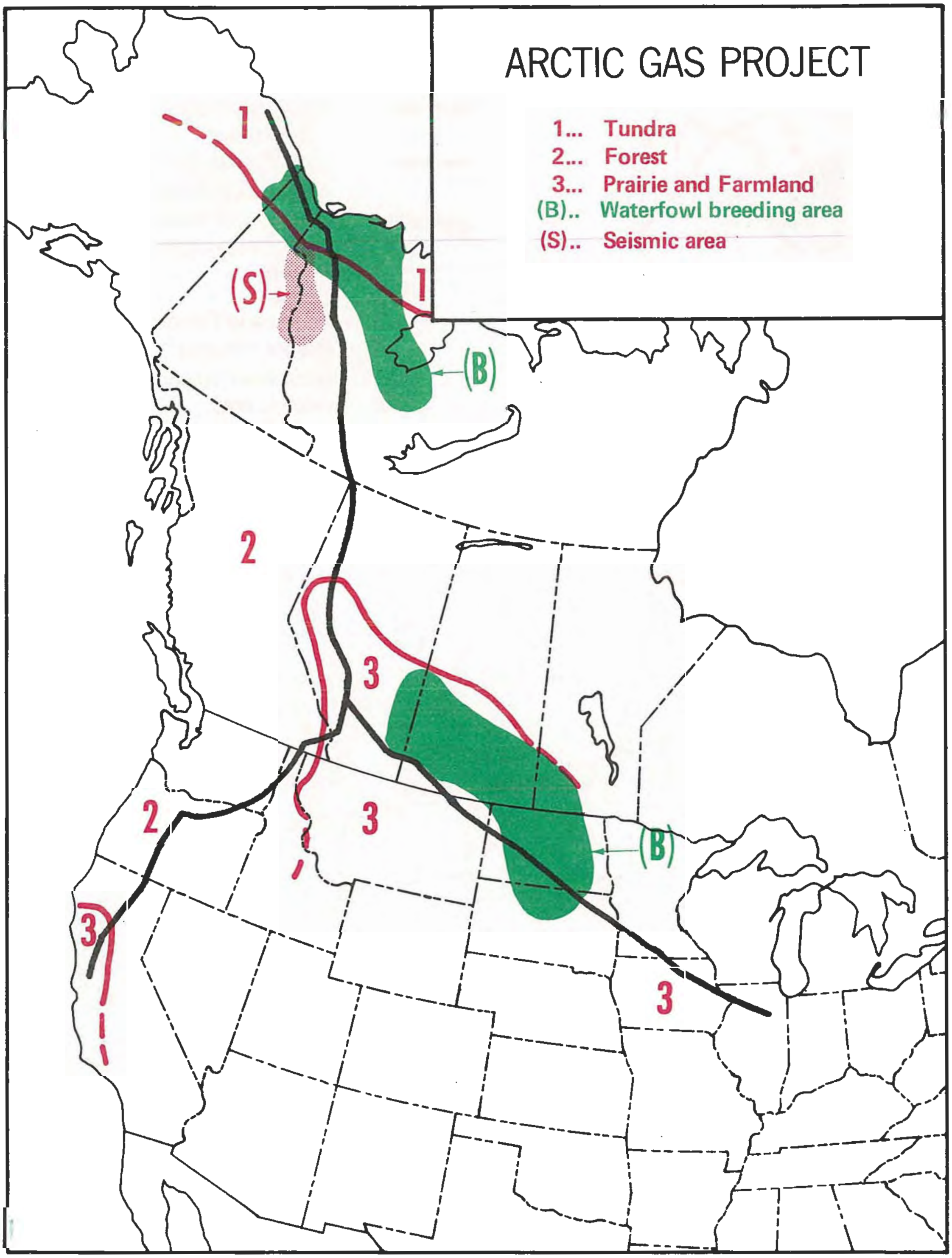

Exhibit V – 6: Environmentally Sensitive Conditions Along Proposed Route.

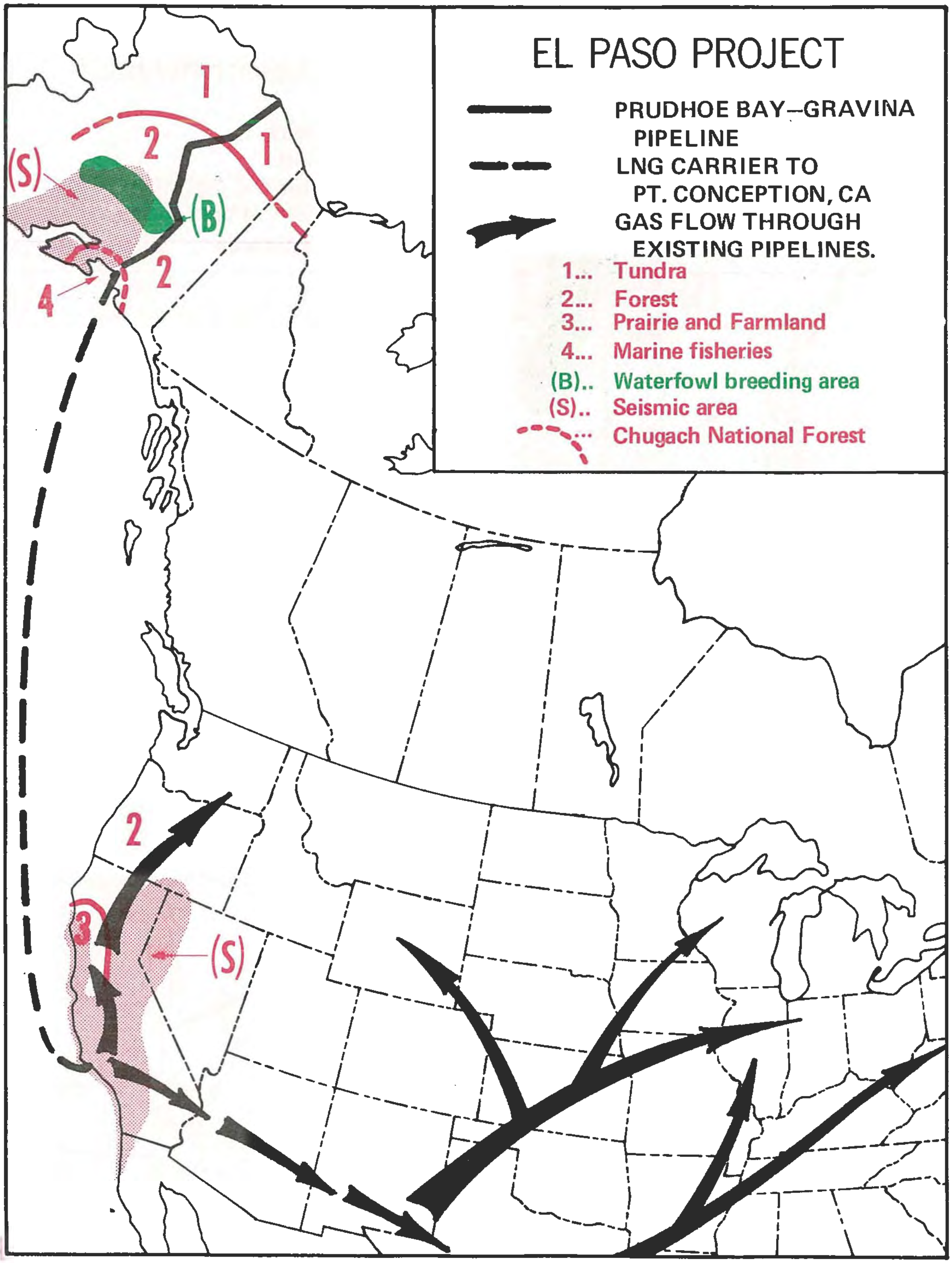

Exhibit V – 7: Environmentally Sensitive Conditions Along Proposed Route.

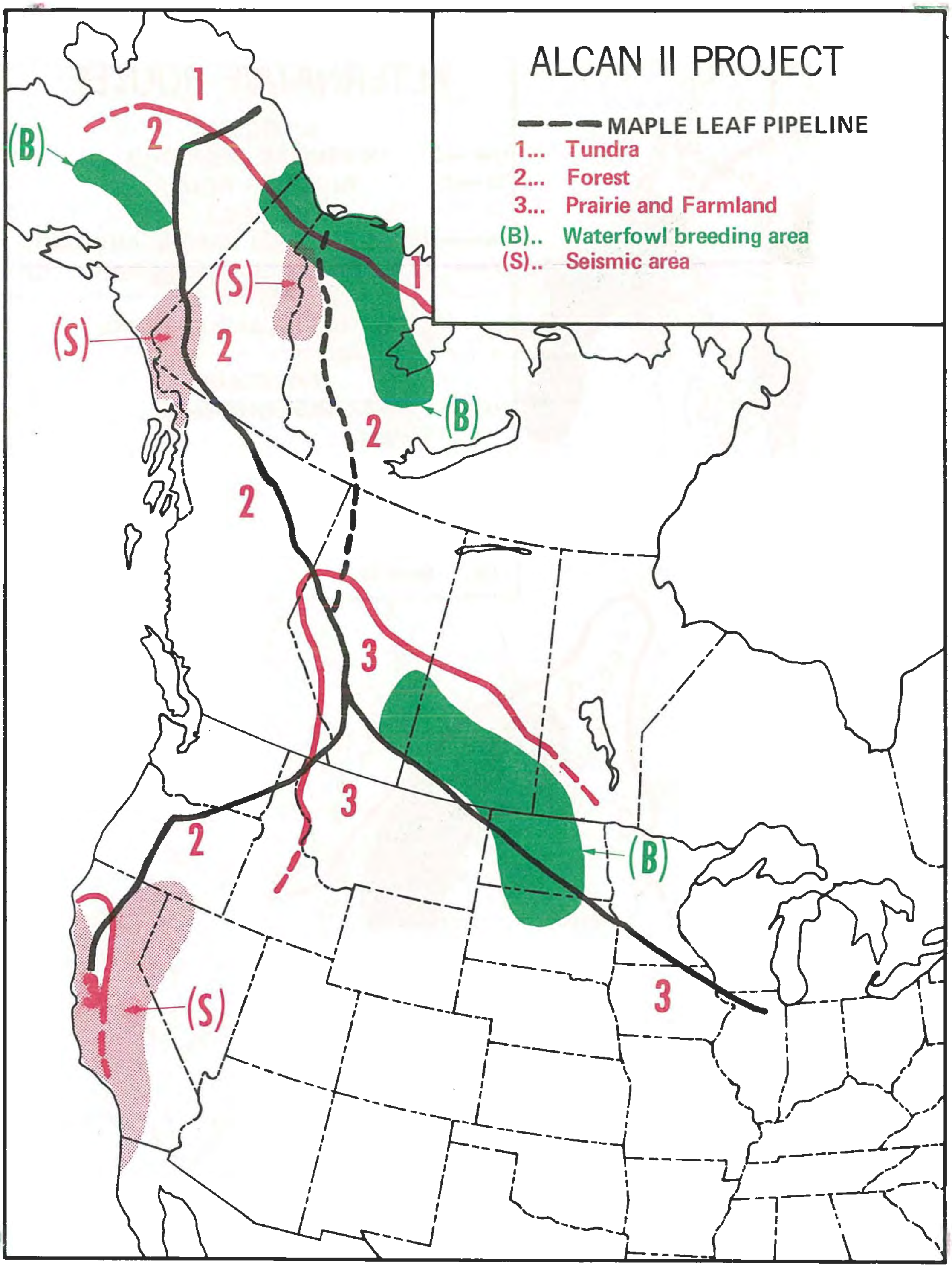

Exhibit V — 8: Environmentally Sensitive Conditions Along Proposed Route.

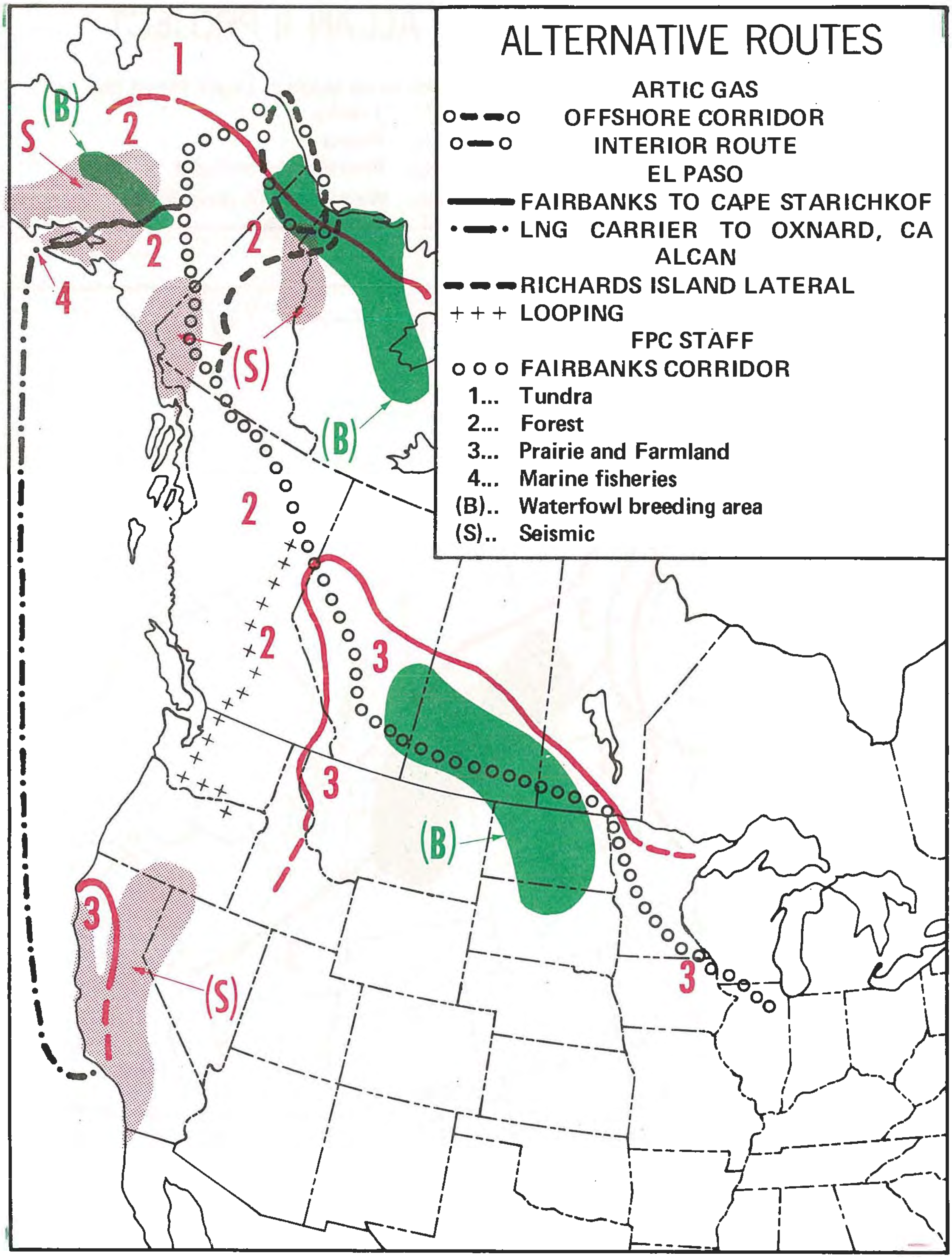

Exhibit V – 9: Environmentally Sensitive Conditions Along Proposed Route.

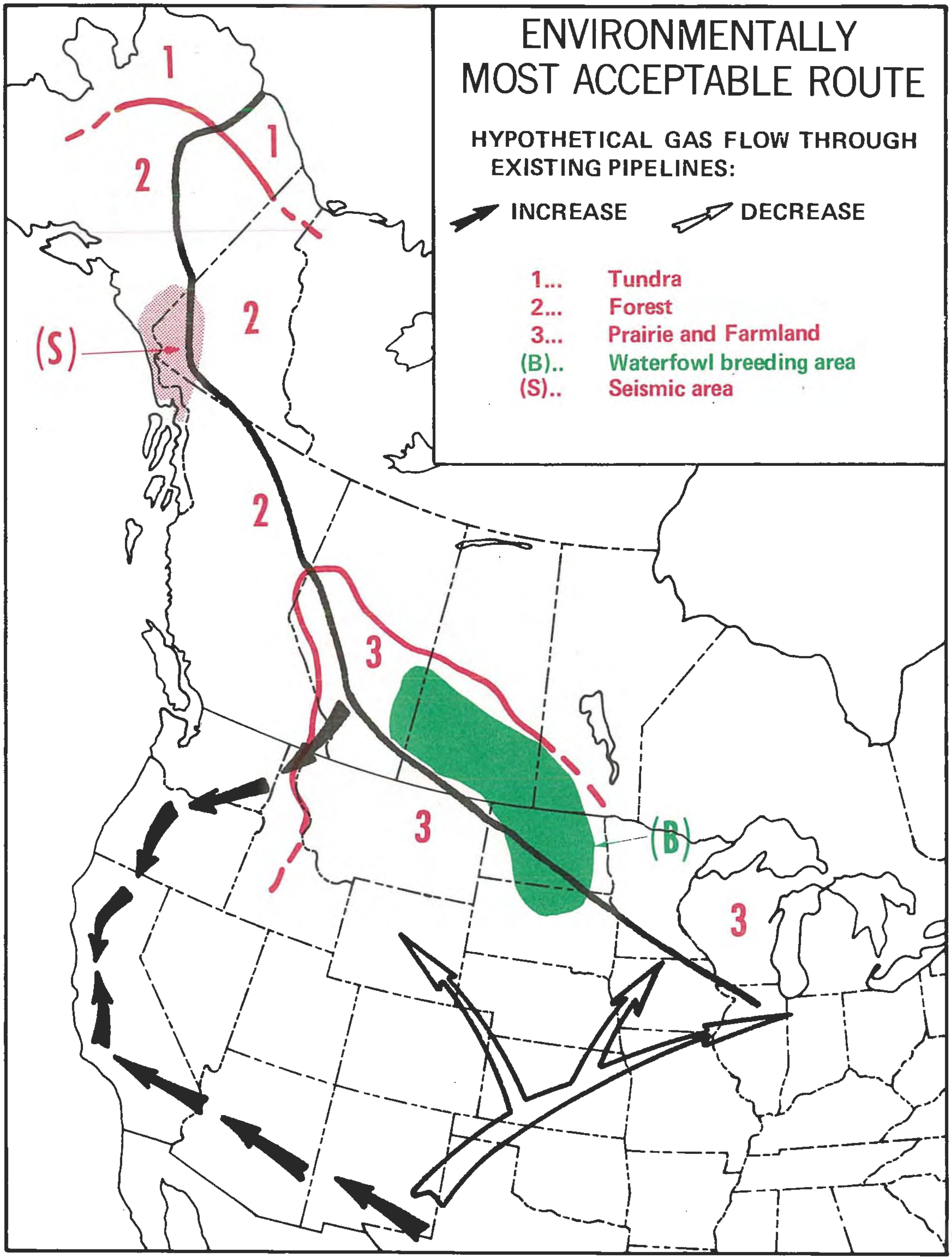

Exhibit V - 10 (see also Exh. V - 5). Environmentally Sensitive Conditions Along Environmentally Most Acceptable Route.

CHAPTER VI

SOCIO-ECONOMIC IMPACTS

A. Introduction

In this chapter we assess the social and economic impacts of construction and operation of each of the competing trans-Alaska gas pipeline systems on specific geographic areas: Alaska; Canada; California; the "Northern Border" states of Montana, North and South Dakota, Minnesota, Iowa, and Illinois, and the Pacific Northwest states of Washington, Oregon and Idaho.

Our principal sources of information are the record, including the final environmental impact statements (FEIS), the socio-economic briefs of the parties, and Judge Litt's decision. Several economic models were relied upon by the various parties and Staff, but we have used primarily the model runs and projections of the Staff, the Department of the Interior, and Alcan which were developed by the Institute for Social, Economic and Government Research of the University of Alaska (ISEGR) as a part of the Man in the Arctic Program (hereafter cited as the "MAP model"), including later runs in a study prepared for the Alaska Department of Commerce and Economic Development by Battelle Memorial Institute.

We note that when applied to large projects these model results are subject to a high degree of error, as much as 30 percent or more in some cases. Therefore, the analyses are necessarily judgmental and uncertain as to absolute values. However, these models are highly useful in illustrating the relative impact relationships among the several projects.

1. Alaska

Judge Litt accurately summarized the issue:

"As far as the United States is concerned, the primary socio-economic effects which are definable at all are concentrated in the State of Alaska. Since the overwhelming benefit to the State, regardless of the pipeline certificated, will be royalty gas payments and severance taxes, the issue really concerns those additional benefits or costs to the State that might flow from one pipeline project more than from another. On the practical side, the stakes are additional jobs and tax revenues versus pressure from immigration on public and private goods and services." 1/

Each of the proposals would provide a fillip to the economy during the period of construction, and a continuing economic benefit from the operation of the pipeline. Although the number of direct jobs created in Alaska will not be substantial--perhaps 5,000 to 6,000 during the peak of construction for Alcan and El Paso and less than half that number of Arctic Gas--and the long-term employment opportunities will be smaller, there will be a substantial increase in state and local government revenues, mainly from royalty payments and severance taxes. These revenues will in turn support expanded government services and economic development programs.

The Arctic Gas project would have the least impact in terms of population growth, employment, unemployment and public service costs. It would also generate less total personal income, personal corporate spending, and demand for housing, education, social and health services, public safety and recreation. Many of these impacts would be temporary since little remains after construction other than a pipe in the ground and a small work force for operation and maintenance. Arctic's alignment passes only

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1/ I.D. 253, footnote omitted.

one affected village of any size (Kaktovik, 1970 Population 123) and the village supports that route. Thus its impact on native Alaskans (Eskimos, Indians and Aleuts) would be minimal.

El Paso would have the greatest impact. Moreover, it offers the most capability for delivery of natural gas to communities in different parts of the state. El Paso would permanently alter the City of Cordova with its proposed LNG plant nearby, not only during construction, but also throughout its operational life with a work force of nearly 350. The City welcomes the prospect.

Alcan's impact falls between the other two and little else can be said by way of summary about it.

An important question for the State of Alaska is whether it is more advantageous to take its 12 1/2 percent royalty in gas for its own industrial development or to take the royalty in money payment on gas as sold. Because there is little market for such gas in Alaska at present, economic justification for its taking royalty gas is uncertain. The primary deterrent to a large expansion of the market in the future is the cost of transportation of the final products to markets larger than the projected 1990 Alaskan population of over 800,000. Generally, it is less expensive to transport the gas to the lower 48 states than to consume it in comparable industrial activities in Alaska.

2. Lower 48 States

Arctic and Alcan would utilize identical systems in the lower 48 states and would have virtually identical socio-economic impacts. Their construction proposals would have a short-term positive impact on the economies of the Northern Border states. Most of the construction would occur in sparsely settled grazing and wheat-growing areas of Montana and North and South Dakota. Given the low population density of these areas, the relative impacts on employment, income and public services would be greater there than in the more industrialized and populated areas of Minnesota, Iowa and Illinois. After construction, the most significant regional impacts would be the public revenues from property taxes. The presence of a large pipeline with the capacity for expansion could also stimulate coal gasification development in Montana and the Dakotas in the future.

Socio-economic impacts on the Pacific Northwest states are difficult to assess because the required amount of additional pipeline construction is unknown at this time. But even a total looping of existing facilities on the Western Leg would have only minimal and temporary impacts other than on local tax revenue. For all three systems, Portland, Seattle, and the Puget Sound region can be expected to perform their traditional role of supply and remote staging areas for Alaska.

El Paso's proposed LNG facility would have a greater impact on California than would the proposed Western Leg.

The greatest socio-economic long-range benefit to the lower 48 states from any of the system is, of course, delivery of almost 1 Tcf per year of natural gas. Arctic and Alcan have better fuel efficiencies than El Paso, and would thus deliver more gas per unit of input.

3. Canada

Arctic and Alcan's impacts on Canada would be similar. Total population and employment impacts would not be large in the aggregate, though they may be substantial for small communities on a temporary basis. The Alberta skilled labor pool would supply most of the demand. Public revenues and expenditures would increase, primarily due to increases in ad valorem taxes. Income and spending, housing, and public safety impacts would be minor. The principal impact would be on the traditional life and economics of native communities in the Yukon and Northwest Territories, especially those which have been more isolated.

B Comparative Analysis by Kind of Impact

1. Population

The primary population impacts of any of the competing proposals will be centered in the State of Alaska. Historically, major construction projects have been the principal impetus for Alaska's population growth. Between projects, such as the Alyeska oil pipeline, the Cook Inlet hydrocarbon development, the DEW Line, and the gold rush, Alaska's population tends to stabilize at new levels brought about by the latest project. Thus, it is reasonable to expect that this pattern will hold in the case of any gas pipeline project.

Although the different models used by the parties produce varying results, there is no doubt that (1) the statewide population impact will be signficant, and (2) that there are major relative differences between competing proposals.

Using the MAP model for comparison purposes, the Arctic proposal would add 400 persons in 1977, 5,300 persons in 1980, and about 7,000 persons in 1982-93. By 1990, its impact would add about 10,000 to Alaska's base population. 2/ Alcan's impact would add 4,800 in 1977, 13,700 in 1980, and between 13,100 and 13,500 in 1982-83, using Arctic's Fairbanks Corridor alternative as a proxy for Alcan's route. By 1990, it would add 17,800 to the base. El Paso would add 6,600 in 1977, 24,100 in 1980, and about 20,000 in 1982-83. By 1990, it would add 26,000 to the base. (See Exhibit VI-1.)

2/ We question the short-term projected impact of Arctic shown in Exhibit VI-1. Relative to Alcan and El Paso, the projections seem extremely high, given the limited direct expenditures of Arctic in Alaska, as well as their short timing and geographic location. The longer term projections, however, seem reasonable since royalty and severance tax revenues produce significant population effects.

EXHIBIT VI-1

PROJECTED POPULATION FOR ALASKA INCLUDING
PIPELINE GENERATED POPULATION
(In Thousands)

Year	Base Case Without Gas Pipeline	Total-Including Pipeline Generated		
		Arctic	Alcan a/	El Paso
1975	381.8			
1980	482.9	488.2	496.6	507.0
1985	633.3	641.0	647.7	654.7
1990	802.5	812.7	820.3	829.3

a/ The Staff FEIS, from which this table was derived, did not provide totals for Alcan. However, the Staff FEIS at page I-C149 states in describing Alcan that: "Statewide impacts on population ... would be much greater than those projected for the Arctic prime route, but would not reach the levels projected for the El Paso prime route." As a further check on the Alcan estimates the appropriate years' increased population estimates from Table V-2 of the Battelle study (p.V-4) were added to the FEIS Table's Base Case Without Pipeline estimates for those same years, giving the totals as shown for Alcan. They lie between Arctic and El Paso, as should be expected.

Other models project impacts of much different absolute values, such as nearly 47,000 for El Paso's peak impact, but none challenge the general nature and relative degree of impact between the competing proposals as shown by the MAP model.

Population increases in Alaska are a "mixed blessing," 3/ as stated by Judge Litt, because they are accompanied by social disruption and costs, including some upward pressure on prices due to shortages or bottlenecks in some economic sectors. In the past, personal income taxes and other taxes on individuals have rarely offset the added public service costs associated with a major project, such as unemployment insurance, welfare, and public safety, health, and education programs. With the build-up of revenues from gas production, however, the effects on government budgets will be very favorable.

When large projects caused substantial population increases in earlier periods, they also caused significant increases in the unemployment rate. This happened because many more job-seekers migrated to Alaska than there were jobs, which greatly increased the immediate costs to state and local governments assisting the unemployed.

Most of the population impacts would be concentrated in the Anchorage (50 percent of the increase) and Fairbanks areas. However, the imapct on certain other communities will be significant. Though the impacts would generally be transitory for Kaktovik and the Alcan Highway committees, they would be permanent for Cordova, which is only 13 miles from Point Gravina. El Paso's LNG plant construction would more than triple the town's population to 9,100 by 1979, and still nearly double it by 1982, when construction has concluded.

The population impact on Canada cannot be quantified on the basis of our information in the record. The Department of the Interior's Final Environmental Impact Statement projects an increase of about 1,000 to 1,500 by 1981 for the male

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3/ I.D. 258.

working age population, and an increase of between 2,400 and 4,400 for the total working age population. The Staff FEIS makes no population projections for Canada, but infers that the impact is minimal for either project crossing Canada.

Population impacts appear to be negligible in relative terms for the Pacific Northwest and the northern border states. There would be nearly 1,800 workers needed in Santa Barbara County, California, for LNG plant construction at Point Conception, should El Paso be certificated. However, most of this demand (1,500) is expected to be satisfied from the local labor pool.

2. Public Revenues

The selection of one proposal over another will not have a major long-term impact on public revenues since the vast majority of these revenues will accrue to the State of Alaska in the form of royalty and severance taxes on the gas produced, rather than from construction-related causes. Direct construction employment and multiplier effects, however, will generate additional tax receipts which will be higher for El Paso and Alcan than for Arctic Gas.

Unfortunately, we do not have adequate data to assess the relative net revenue benefit of the competing proposals, partly because capital costs of expanded public services were ignored in El Paso's projections of public service costs. 4/ Therefore, El Paso's net benefits are overstated, especially considering the major capital costs to Cordova.

Although the state government imposes a substantial personal income tax averaging 7 percent, the value of such taxes in offsetting increased public service costs has been limited in

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4/ TR.63/9627-8. Testimony of Dr. John M. Craig on cross-examination: "Q. Now, these are operating costs only, are they not? A. That is true. We did not include the capital costs from the standpoint that we believe the facilities necessary to support an El Paso project will have already been constructed for the Alyeska project."

We disagree that all the facilities which would be needed have already been constructed due to Alyeska activity. For example, there will be large capital costs associated with the major peak employment and population increases at Cordova of 3,139 and 9,100, respectively. Facilities construction was evidently restrained by the uncertainties surrounding the Alyeska project and budget constraints on government entities. These factors will not be restraining in the case of a gas transportation project.

the past because of a relatively low collection rate. In the case of Alyeska workers, for example, the paychecks were often mailed by employers out of state and were received by persons (e.g., wives of workers) who resided in other states. The tax leakage from this source may have been substantial. Furthermore, even if tax withholding can be made effective, the mailing of paychecks out of the State, which means that they will not be spent in-state, will limit the tax revenues produced from the multiplier effects of such spending.

Exhibit VI-2 depicts MAP model projections done by Battelle Memorial Institute for the Alaska Department of Commerce and Economic Development and shows that State of Alaska and local government revenues from all pipeline related sources, including royalty and severance taxes, may increase by about $200 to $400 million per year by 1990, depending on the pipeline system chosen.

Total revenues vary significantly, depending on the assumptions of production and the price of natural gas. As shown in Exhibit VI-3, at low wellhead prices the higher property taxes of Alcan and El Paso show up significantly. However, at a production rate of 2.5 billion cubic feet per day and higher net-back wellhead prices, the annual revenues vary by only 5 percent between the competing proposals. Therefore, it becomes even more important to assess public service costs of each proposal to determine the net revenue benefits.

As for Canadian entities, public revenues would come primarily from ad valorem taxes on the pipeline facilities when constructed. Total estimated revenues to the Yukon Territory in 1981 are $37.5 million, which represents two-thirds of its 1976 revenues. Obviously, the Yukon impact is significant. British Columbia estimated revenues are $54.7 million, which represents only 1.5 percent of its 1976 revenues. Alberta revenues would be $32.5 million and Saskatchewan $8.3 million in 1981, or 1.2 percent and 0.7 percent of 1976 revenues, respectively.

EXHIBIT VI-2

Impacts on Alaska - Total Increase In State and Local Government Revenues ($Millions)(a)__/

Routes	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Arctic	0.6	1.7	12.9	54.4	154.3	135.4	132.1	135.1	140.5	147.0	154.6	163.2	173.2	185.2	199.4
Arctic Alternative (Alaskan Highway)	2.4	7.0	47.8	95.5	212.8	190.9	188.6	193.9	202.4	212.3	223.8	237.1	252.5	270.7	292.7
El Paso	0.8	1.9	55.4	134.1	276.7	279.9	253.4	253.3	263.0	276.6	293.1	312.4	335.1	365.3	397.2

___/ Results of MAP model simulation supplied by Dr. M. J. Scott, University of Alaska, March 1977.

This table, as well as the others contained in this section, uses nominal dollars, assuming an inflation rate of 6%.

EXHIBIT VI-3

Annual Increase in State Revenues Due to
Change in Price and Production Levels -
1981 through 1990
($ Millions)

	Price ___/ $/MCF	Revenue (a) 2.5 BCFD	Price ___/ $/MCF	Annual Revenue(b) 2.0 BCF	Annual Revenue(b) 2.5 BCF	Annual Difference 2.0 BCF	Annual Difference 2.5 BCF	Cumulative 1981-1990 2.0 BCF	Cumulative 1981-1990 2.5 BCF
El Paso	.50	147.29	1.29	227.37	266.22	80.08	118.93	801	1189
Alcan	.50	119.30	1.40	212.63	254.79	93.33	135.49	933	1355
Arctic	.50	85.22	1.62	205.05	253.83	119.83	168.61	1198	1686

(a) Revenues are based upon MAP model and include royalty tax (12.5%) severance tax (4%) and property tax (20 mil).

(b) Assumes same property value as used in MAP model and tax rates are the same for both cases mainly, 20 mil property tax, 4% severance tax and 12.5% royalty tax.

___/ The price of $.50/MCF is considered here as illustrative, for the purpose of determining the relative values for the different proposals. At the time of model construction it was considered a reasonable low figure. This may not now be the case.

___/ These are "net-back" wellhead prices derived by Battelle when it became apparent that the $.50/MCF price probably was unrealistic. "Net-back" wellhead price is derived from a set of assumptions involving the BTU equivalency of gas and No. 2 fuel oil, allowance of a 10% premium for gas, and the validity of the "as advertised" tariffs for the competing systems. It is defined as market value less transportation expense, and is similar to the formula price method discussed in Chapter 12.

In the Pacific Northwest states additional _ad valorem_ taxes would yield from $1.5 to $3 million per year. For the northern border states, additional _ad valorem_ taxes would amount to $39.6 million annually, or an average of $500,000 per county per year. In California, increased local and state annual revenues of about $14 million would be expected from the LNG facilities at Point Conception and its associated employment.

3. Public Expenditures

Whichever project is certificated, Alaska state and local government expenditures will increase. Not only will there be an increased demand for services, but there will also be an opportunity to finance new and improved government programs as more revenue becomes available. As shown in Exhibit VI-4, by 1990 the increase is projected at $160 million for the Arctic proposal, $237 million for Alcan, and $326 million for El Paso at $.50 gas and 2.5 Bcfd production. 5/

These figures are understated, however, because we believe that capital costs, particularly in areas such as Cordova which was not impacted by Alyeska, are an important component of public service costs. They are left out of El Paso's cost projections. At a higher assumed wellhead price, which would increase royalty and severance revenues, government expenditures would also be higher.

Using the Battelle analysis previously described, netback prices would be $1.62 per Mcf for Arctic, $1.40 for Alcan, and $1.29 for El Paso rather than the $.50 price in Exhibit VI-3. Even at an assumed savings rate of 25 percent for the general fund and 2.0 Bcf per day production, these prices would cause state and local government expenditures to rise by $220 million for Arctic, $307 million for Alcan, and $416 million for El Paso. As noted above, we would expect government spending to be spurred by increases in revenues.

5/ Illustrative only for the purpose of determining relative impacts. See Exhibit VI-3 footnote.

EXHIBIT VI-4

IMPACTS ON ALASKA - INCREASE IN STATE AND
LOCAL GOVERNMENT EXPENDITURES (TOTAL IN
MILLIONS OF DOLLARS AND PER CAPITA IN DOLLARS a/
PER CAPITA VALUES BASED UPON 50¢ & MAP)

ROUTES	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Acrtic															
Total	0.5	1.4	10.7	48.0	118.4	100.9	98.1	101.0	106.2	112.2	119.3	127.3	136.5	147.4	160.5
Per Capita	1	-9	-42	6	146	107	86	75	69	66	63	63	63	63	65
Arctic Alternative (Alaskan Highway)															
Total	2.0	6.0	38.7	78.7	162.7	142.5	140.8	145.9	153.9	163.1	173.8	186.1	200.2	217.0	237.2
Per Capita	4	-30	-7	30	196	146	119	105	96	91	87	86	87	87	90
El Paso															
Total	0.7	1.7	46.1	113	215.9	216.8	192.9	193.0	202.2	214.8	230.1	248.0	268.8	296.5	325.8
Per Capita	1	-58	-46	28	198	208	140	112	98	92	87	87	87	93	96

a/ Results of MAP model simulation provided by Dr. M. J. Scott, University of Alaska, March 1977.

For Canada, the projections of increased public expenditures are small, except in sparsely settled areas where the relative impact may strain local communities during construction. These effects will be transitory (3 to 6 months), however, and will be more than offset by increased ad valorem taxes after completion of the line.

Increases in public service costs in the Pacific Northwest and northern border states will be relatively small under any of the proposals. Greater costs would be incurred in California under the El Paso proposal, but the overall impact should be small, and would be offset by increased revenues from taxation of the LNG facility and its employees.

4. Employment and Unemployment

New jobs will be created in Alaska by any of the proposals and will roughly parallel their population impacts. Arctic will generate the least employment, Alcan next, and El Paso the highest. Construction will provide the most jobs; hence peak employment generally occurs midway through each proposal's construction period in the State. Pipeline operation employment is of much less significance, except for El Paso's proposal due to operation of its LNG facilities.

Miles of pipeline construction within Alaska and employment impact are closely related, so that the longest route (El Paso's) produces the greatest employment. The MAP model shows peak (1979) direct and indirect employment as 7,300 for Arctic, 10,300 for Alcan, and 16,100 for El Paso. Exhibit VI-5 summarizes a more detailed analysis by Battelle Memorial institute as reported in their recent study, Alaskan North Slope Royalty Natural Gas Use (1977).

It should be noted that statewide employment will increase after termination of construction, primarily because state and local government employment will increase with the increase in revenues from gas production and pipeline operation. Historically, government in Alaska has accounted for nearly 60 percent of total employment in the State. Since revenues from

EXHIBIT VI-5

ESTIMATED EMPLOYMENT IN THOUSANDS INDUCED BY EACH OF THE PROPOSED PIPELINE ROUTES

Year	Arctic		El Paso		Alcan	
	[a]	[b]	[a]	[b]	[c]	[b]
1978	0.3	6.0	3.1	13.2	11.5	8.3
1979	1.2	7.3	12.2	16.1	11.2	10.3
1980	2.7	5.5	21.3	14.6	2.6	7.6
1981	2.2	4.5	20.1	10.7	-	6.8
1985	3.2	4.4	12.2	9.7	-	6.7
1990	4.6	5.6	14.7	12.8	-	8.8

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[a] The Aerospace Corporation, Alaskan Natural Gas Transportation Systems Economic and Risk Analysis: Final Conclusions and Results, pp. 11B-8, February 1976.

[b] MAP model simulation.

[c] Resource Planning Associates, Evaluating the Use of North Slope Natural Gas in Alaska, pp. 4-2, October 1975. (Data available for construction phase only.)

royalty, severance, property, and other hydrocarbon taxes will be substantial for the producing life of the fields (as much as $1.2 billion in 1980, for instance) it is reasonable to expect that government employment will increase substantially. Model projections vary between 1,870 and 3,900 for 1990, depending on which proposal is certificated.

High unemployment historically has been associated with high project employment opportunities in Alaska. This was confirmed by experience during construction of the Alyeska oil pipeline, where even with the high levels of employment, the peak unemployment rate was near 12 percent.

Certain factors may mitigate this phenomenon for the gas pipeline project, however. It should be noted that the peak employment on the Alyeska line in 1974 to 1976 coincided with the severe recession in the "lower 48" during that same period. This caused a larger than normal influx of job-seekers. Nearly 20,000 or more were available but without jobs at times during those years. In contrast, the national economy is likely to be much stronger during the initial and peak periods of gas pipeline construction. Secondly, since experienced pipeline workers are now located in Alaska as a result of Alyeska construction, there should be a restraining effect on immigration by job-seekers who realise that fact. A third factor is the action which government and the private sector have taken, based on the Alyeska experience, to discourage job migration to Alaska via advertising and airport advisories.

Exhibit VI-6 shows projected total employment in Alaska to 1990.

Employment and unemployment impacts on Canada would be minor, though small communities may experience relatively major employment opportunities, especially for natives. It is estimated that British Columbia and Yukon construction employment demands of as many as 3,375 workers at the peak and Alberta and Saskatchewan demands of over 1,000 would be met 80 to 90 percent by the Alberta skilled labor pool, the rest from local sources. Operation and maintenance employment

EXHIBIT VI-6

TOTAL EMPLOYMENT IN ALASKA INCLUDING
GAS PIPELINE GENERATED EMPLOYMENT
(Thousands of Workers)

Year	Base Case Without Gas Pipeline	Total Including Pipeline Generated	
		Arctic	El Paso
1975	183.1		
1980	235.0	238.6	249.6
1985	317.6	321.8	327.3
1990	403.8	409.0	416.6

Source: January 1976 runs of MAP regional model would be negligible. All needs would be met by Canadian workers, including some natives, who represent only about 2 percent of the total population of the affected provinces. They represent larger percentages, of course, in the Yukon and Northwest Territories.

Impacts would be minimal for the Pacific Northwest and the northern border states, because annual employment will average only a few hundred persons, except for some of the sparsely settled counties where pipeline construction would provide relatively large employment opportunities. The El Paso LNG facility construction of Point Conception, California would mean 1,800 additional jobs in Santa Barbara County, 1,500 of which would be filled locally.

5. Income and Spending

Canada would be the most affected in terms of income and spending by the Arctic and Alcan proposals. Alaska and California would be most affected by the El Paso proposal. Alaska would be significantly impacted by Alcan.

As shown in Exhibit VI-7, Battelle's updated MAP model projects increases in total personal income in Alaska by 1990 to be $189 million for Arctic, $292 million for Alcan and $437 million for El Paso.

Using earlier data of comparable magnitude, the Staff FEIS permits comparison of personal income on a per capita basis in Alaska. As shown in Exhibit VI-8, per capital personal income would be positive through 1990 for the Arctic proposal, peaking in 1979 with a $53 increase. (See Exhibit VI-8.) El Paso contrasts by peaking at a $315 increase in 1978 but then changing to a negative impact from 1983 to 1990, reaching minus $36 in 1985-87. This negative phenomenon is apparently due to both the large population effect of El Paso and to the much larger increased employment effects of El Paso, including lower-paying occupations. It does not necessarily mean that any given individual would be worse off, but simply that the averages will be lower.

Finally, we note that El Paso's "Mid 1975 Socio-economic Report: Trans-Alaska Gas Project" shows that the major impact on income and spending would be concentrated in the South Coastal Study Area, which includes Anchorage and Cordova. Its study projects $440 million in direct wages for construction activities during the 1977-81 period, and about $8 million per year thereafter in operating personnel salaries and wages.

In Canada, the income and spending impact has not been fully assessed, but from what we know of population, employment, and public revenue estimates, it will not be significant. Per

EXHIBIT VI-7

IMPACTS ON ALASKA - INCREASE IN TOTAL STATE PERSONAL INCOME DUE TO GAS PIPELINE ($ MILLION) a/

ROUTES	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Arctic	0.4	27.7	149.5	181.6	111.5	95.9	95.5	100.5	107.8	116.5	126.6	138.3	152.1	168.8	189.0
Arctic Alternative (Alaskan Highway)	1.6	90.9	189.5	241.2	157.8	142.4	144.5	153.0	164.6	178.3	194.3	212.6	234.1	260.4	292.2
El Paso	0.6	121.0	296.5	363.9	322.1	234.2	216.3	222.9	238.8	258.9	283.2	311.3	350.4	388.6	437.4

a/ Results of MAP model simulation provided by Dr. M. J. Scott, University of Alaska, March 1977.

EXHIBIT VI-8

IMPACT OF ALTERNATIVE PIPELINES ON PERSONAL INCOME IN ALASKA

Pipeline & Year	Personal Income (Millions of (Dollars)	Personal Income Per Capita (Dollars)	Real Per Capita Personal Income (1967 Dollars)
Arctic			
1977	8.4	11	5.1
1978	36.3	49	19.8
1979	53.3	53	22.1
1980	73.2	38	14.9
1981	81.5	37	14.1
1982	87.7	30	11.1
1983	94.2	22	7.9
1984	101.6	18	5.9
1985	109.9	13	4.1
1986	119.3	9	2.9
1987	130.2	6	1.9
1988	143.0	4	1.2
1989	158.5	4	0.9
1990	177.1	3	0.9
El Paso			
1977	121.0	151	67.5
1978	296.5	315	135.7
1979	363.9	289	119.9
1980	322.1	141	56.5
1981	234.2	28	10.8
1982	216.3	9	-3.1
1983	222.9	-27	-9.4
1984	238.8	-32	-10.8
1985	258.9	-36	-11.7
1986	283.2	-36	-11.4
1987	311.3	-36	-11.0
1988	350.4	-31	-9.0
1989	388.6	-30	-8.5
1990	437.4	-26	-6.9

Source: January 1976 runs of MAP regional model.

capita income will be increased generally, and may show significant increases in sparsely settled areas and among native workers who are currently unemployed or employed at lower wages. The income effect of direct and indirect employment in the Yukon and Northwest Territories is estimated at less than $20 million. It should be somewhat higher for Alberta and Saskatchewan.

Income and spending impacts would be minimal on a relative basis for the Pacific Northwest, and somewhat greater for the northern border states. The impacts in California would be significant in absolute terms in the local area where El Paso's LNG facility would be built. Total construction payroll would be about $96 million.

6. Social and Health Services

The Alyeska construction has contributed to a growth in Alaskan health services which should serve the gas pipeline project needs without much difficulty. Physician/patient ratios are favorable, health care facilities have expanded, physician's assistants have gained experience from construction camp work, and private companies generally provide free medical programs for their employees. State and local governments have the recent Alyeska experience to draw on in providing social services for large projects. However, drug and alcohol abuse will probably continue to be a problem.

As with the other impacts, the least social service impacts will accure from the Arctic proposal, and the most from the El Paso proposal.

As for Canada, the effects would be minor and transitory, except for some greater demand for social services in sparsely settled areas due to the relative size of the pipeline employment and population impact.

The social and health service impacts appear to be relatively minor for the Pacific Northwest and the northern border states.

Since 1,500 of the 1,800 new jobs at El Paso's LNG facility would be filled by local residents, the California impact would be minor.

7. Housing

In Alaska, housing has been scarce and expensive for some time, especially during Alyeska construction. However, the Alyeska construction did trigger the building of a large number of units and this may ease the impact of the gas pipeline project somewhat.

The Arctic proposal would have the least impact on Alaska. It is estimated that an additional 1,100 units would be required by 1983 in Canada as a result of pipeline construction, 860 of these being related to the indirect and induced impact. This impact is quite small. Most housing demand in Alaska and Canada will be met by the construction camps.

Alcan's proposal would have a substantial impact both in Alaska and Canada, but it would be mitigated in Alaska owing to a route which follows Alyeska construction and then built-up areas within established transportation routes.

El Paso would have the greatest impacts in Alaska and, of course, in California. While its impacts would be similar to that of Alyeska along most of its route, the demand for housing in Cordova would be greatly increased since the population would more than triple at peak construction.

Impacts on the Pacific Northwest and northern border states would be relatively minimal, since construction camps will meet most requirements in sparsely settled areas, and the supply of housing is adequate in the more heavily populated ones.

8. Public Safety

Crime in Alaska, both against persons and property, rose substantially during Alyeska construction. It increased 27 percent from 1973 to 1974 and 55 percent in the first six months of 1975 over the previous year. A similar effect can be expected in all geographic areas of construction. In Alaska, the least impact will come from Arctic's proposal, the greatest from El Paso's. Both Arctic and Alcan will create added problems of public safety in Canada, but the effect should be minor. Some minor impacts would be anticipated in California near El Paso's LNG facility. In the Pacific Northwest and the northern border states there will be the usual traffic and recreation-related problems.

9. Native and Community Impacts

In Alaska, Arctic's proposal would impact Kaktovik, but the village has gone on record favoring the increased employment and economic activity Arctic would bring. The project's other local effect would be primarily to draw native Alaskans from their home communities to the construction area, supplying employment and contributing to the major change toward a cash economy that is already underway for the native population. In most parts of Alaska the trend toward mixed cash and subsistence economies has been rapidly promoted by the Alyeska construction and the Alaska Native Claims Settlement Act. In Western Canada, the situation is somewhat different, since no major project, such as Alyeska's, has been recently constructed. Understandably, people have mixed feelings about the impact of pipeline construction on traditional life, although the native population for the most part already has a mixed economy, except in very isolated areas.

Alcan would have important impacts in Alaska, specifically on the non-native communities of Deadhorse, Wiseman, Livengood, Fairbanks, Delta Junction, and Tok. Though no native villages are located directly in the pipeline corridor, it would greatly impact the native villages of Dot Lake, Tanacross, Tetlin, and Northway. To date, Alcan has provided only narrative descriptions of these communities, and the impacts have not been adequately assessed. From that description, it appears that pipeline construction will have different effects on the four primarily native villages. Dot Lake and Tanacross, and to some degree Northway due to its proximity to the FAA station, exhibit a major degree of acculturation to non-native activities, while Tetlin has chosen a more isolated and traditional way of life. Pipeline construction will provide employment opportunities for those who wish it, while posing some difficulties due to the proximity of mostly non-native pipeline workers in nearby construction camps.

El Paso's impacts in Alaska would resemble those of Alyeska, since the routes are quite similar. Cordova would experience the same relative degree of impact as Valdez, causing major dislocations. A tripling of Cordova's population at peak LNG facility construction has obvious implications for employment, unemployment, public costs and revenues (including capital costs) housing, education, social and health services, and public safety. It should be noted that Valdez was able to raise $2 billion in industrial revenue bonds for the financing of Alyeska's facilities and its own needs. However, at this time, Cordova has no taxing jurisdiction over Point Gravina where the facility would actually be located.

As for preservation of native lifestyles, any gas project would accelerate the trend toward modernization. It would not fundamentally alter any Alaska community, as has occurred at Anaktuvuk Pass with Alyeska construction. Snowmobiles have replaced dogsleds in Kaktovik and in such indirectly affected places as Barrow. More important than these effects of pipeline construction on the native peoples would be the effects of tax revenues from gas production and property taxes and the continuing impact of the activities of the native corporations under the Alaska Native Claims Settlement Act.

C. Overall Assessment of Socio-Economic Impacts

As noted at the outset of this Chapter, the principal benefits to the state will be largely independent of which pipeline system is certificated. These benefits will flow from the increased government revenues from royalty payments and severance taxes and, to a lesser extent, from the operation of the pipeline itself. El Paso would generate more jobs, more personal income, more property subject to tax, and more indirect economic activity than would the other proposals, but it would also require more social services and would probably be associated with the highest unemployment. These impacts would be much smaller for Arctic Gas and somewhere in between for Alcan. On the other hand, there is a possibility that Arctic Gas, with its lower projected transportation cost, would produce higher royalty income for Alaska, which will in turn aid the state in financing industrial development and expanding its social services.

All in all, we find that these contrasting socio-economic impacts, while of interest in and of themselves, offer little guidance for the final choice among the competing applicants.

CHAPTER VII

GEOTECHNICAL ISSUES AND SYSTEM RELIABILITY

This chapter addresses the geotechnical and other factors affecting the reliability of each of the competing transportation systems. We consider the likelihood of interruptions of service of each system once placed in operation, and the probable durations and methods of overcoming such interruptions. Because issues of LNG safety and siting are closely bound up with reliability, we also consider in this chapter the question of the best site for El Paso's liquefaction facilities in Alaska, and its regasification facilities in California, should that alternative be chosen.

We will consider several separate factors which could imperil continued operation of one or more of the transportation systems. Some of these factors, such as metallurgic reliability and soil stability, will affect each of the pipeline systems, though in differing degrees. Others, such as LNG system reliability or ultra-high pressure operation, present problems peculiar to one or two of the systems.

Obviously, a great number of subsidiary judgments are involved, but on balance we conclude that each of the systems is adequately reliable for the transportation of Alaskan natural gas. We do believe that the El Paso system, because its facilities are in extremely active seismic zones, and because its interrelated network of pipelines, ships, and terminal facilities is highly complex, represents a somewhat higher risk of at least some interruption of service. On the other hand, the segmented nature of El Paso's operation, involving the use of multiple ships and gasification trains, suggests that under most circumstances, the outcome of an untoward event will be a partial, rather than a total, cessation of supply.

A. Seismic

All three systems will go through areas of potential seismic risk. 1/ The Arctic facilities, because they will leave Alaska on a direct easterly route, and plunge into the interior of Canada, will avoid the major dangers associated with the Circum-Pacific seismic activity so characteristic of southern and south central Alaska, as well as coastal California. Even so, Arctic will have to traverse certain areas in the Yukon-Northwest Territory border area where earthquakes with Richter magnitudes as great as 6.5 have occurred, and exhibits indicate that the maximum expectable earthquake anywhere along the line could be as high as 7.0 on the Richter scale. 2/

The proposed Alcan route contains at least two portions where earthquakes as great as Richter magnitude 8 could be experienced. These are the Denali Fault, which Alcan's route parallels but does not cross, 3/ and the Shakwak Fault in Canada. The latter could be the source of a large quake, though Alcan argues that the fault is "most likely" not active. 4/ Alcan states that its design is adequate for a magnitude 8.5 earthquake, and that its contingency planning includes special pipe, and ditching procedures for the crossing of active faults, should such be discovered. 5/

The feasibility of designing against these risks is not seriously attacked by the other applicants. They do contend that Alcan's actual preparation is simply insufficient to support a determination of the adequacy of their procedures. We find, on the evidence, that Alcan can develop and properly implement an appropriate design. 6/

1/ See Ex. AP-13, Fig. 3.1-10.

2/ Ex. ST-27, at pp. 117, 642.

3/ ST-52, at 49, 52; Tr. 35,027.

4/ Tr. 33,217, 38,849; ST-27 at 745-6.

5/ Tr. 38,183-84, 38,368-71.

6/ See, *e.g.*, Tr. 38,750-53; 38,842-43.

The El Paso system, by its very nature, requires a pipeline into, and major terminal facilities in the vicinity of, the major earthquake prone areas of southern Alaska. Either of the two sites primarily advanced for a terminal, Gravina Point or Cape Starichkof, would be close to the Anchorage and Valdez areas, so recently devastated by the 1964 earthquake. Similarly, either of the proposed southern California sites, Oxnard or Point Conception, would be near, and on the seaward side of, major fault systems, which could affect the pipelines taking gas from the plant to major market areas, as well as the facilities themselves. 7/

While the specific merits of the alternative facilities at each end of the pipeline will be discussed later in this chapter, there is little doubt that earthquakes of a force equivalent to the greatest ever recorded (Richter magnitude 8.5 or more) could conceivably strike both areas.

El Paso recognizes that its pipeline must cross several seismically active areas to reach terminal facilities at Gravina Point. The most important of these along the proposed route are the Donnelly Dome Fault, the Denali Fault, and the McGinnis Bay Fault. 8/ These are all parts of the general Denali Fault System, as shown on the accompanying map (Ex. VII-1). This area could experience earthquakes as great as Richter magnitude 8.0. 9/ El Paso concedes that it does not yet have a specific design to surmount these problems, but that such a specific design both for the pipeline and the LNG facility, is simply a matter of spending the time and money, which is already budgeted.10/ We are not convinced that it is now adquately budgeted. See Ch. VIII. El Paso plans to use a design basically similar that of Alyeska, 11/ and the record contains some testimony as to the type of ditching and pipe contemplated. 12/

7/ See generally WL-14, ST-20.

8/ ST-19, p. 263; Tr. 25,932-33.

9/ ST-22, II-104.

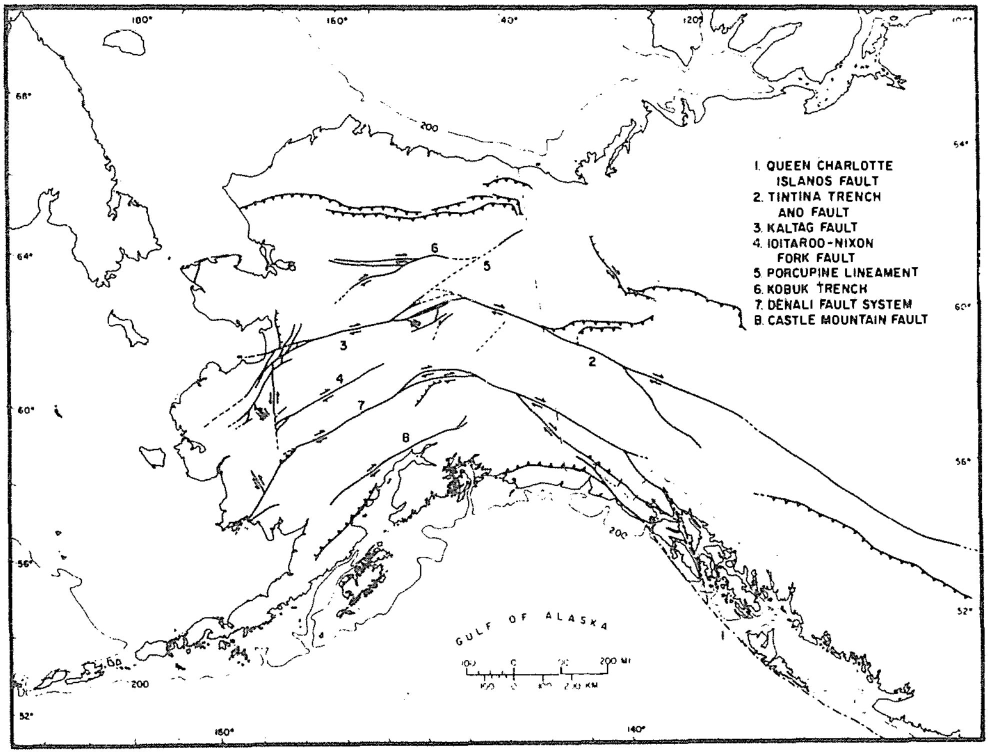
10/ Reply Brief on Geotechnical Matters, pp. 35, 39-40.

11/ Tr. 9,013-15.

12/ Tr. 6295-6306; Ex. EP-62.

EXHIBIT VII-1

MAJOR FAULTS OF ALASKA



Ref: Alcan Pipeline Company March 22, 1977 Filing; Supplementary Data, Section 6. Prepared by Geophysical Institute, University of Alaska (as taken from Stone, 1973).

El Paso states that its proposed facilities at Gravina Point would be anchored to bedrock, which is found within 10 to 40 feet of the surface, and would be designed to withstand an earthquake of 8.5 magnitude. However, the existence of bedrock is based on a brief site examination, and is not supported by test borings. 13/ There is the possibility of an active fault two miles offshore from the plant site, and even ground ruptures are not inconceivable. 14/ The Cape Starichkof site is subject to somewhat lesser seismic risk, on the order of magnitude 7.5, 15/ but bedrock has not been found there. 16/ While El Paso does not prefer this latter site, for other reasons, it does not contend that an acceptable plant could not be built there because of the seismic conditions.

The immediate motion of the earthquake does not represent the only possible hazard to El Paso facilities. A major seismic event can create vast water movements as well. These are referred to as either a tsunami or a seiche. A tsunami is defined as a "gravitational sea wave produced by any large-scale, short-duration disturbance of the ocean floor, principally by a shallow submarine earthquake, but also by submarine earth movement. . . ." 17/ A seiche is defined as a "free or standing-wave oscillation of the surface of water in an enclosed or semi-enclosed basin (as a lake, land-locked sea, bay or harbor) that . . . continues in pendulum fashion for a time after the cessation of the

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13/ See Tr. 8915-20; 9093-97; 27,012-013.

14/ ST-19, II-267.

15/ FEIS, II-515.

16/ Tr. 23,211-215.

17/ Glossary of Geology, p. 758 (AGI, 1974).

originating force. . . ." 18/ There is substantial evidence of both of these phenomena in the south Alaska coast area.

El Paso contends that its plant would be situated sufficiently far up the beach to render it secure under any credible conditions. This is disputed on the basis that the tsunami spawned by the 1964 earthquake, which provides the best recent evidence of the possible magnitude of a seismic event, was generated over 200 km. out in the ocean, while a tsunami generated somewhat closer to shore would overwhelm the facilities as currently designed.

Thus, while the Staff FEIS 19/ estimates the maximum tsunami runup (height reached on land) at 34 feet, with waves of 20-30 feet, its competitors contend that greater impacts are possible. The FEIS notes 20/ that impacts were greater elsewhere in Prince William Sound during the 1964 earthquake, and that a study indicated that a "design event" might result in runup of 100 feet, and wave height of 65 feet. However, the Gravina Point site is so situated and sheltered that it probably would not face the full force of a design event. 21/

The El Paso facility is designed for a wave of 20 feet when the berths are unoccupied, but only 12 feet when a ship is at the dock. This is probably inadequate. 22/ Plans call for ships to depart immediately upon warning of a large tsunami. The amount of warning time is disputed, but is unlikely to be greater than 20-30 minutes. 23/ While this is adequate time under optimum conditions, disasters tend to occur when least expected, and it is far from certain that the ship would be prepared to depart so rapidly every Sunday morning or Christmas Eve for the next 20 years.

18/ Id., p. 643.

19/ II-515; see also Tr. 9036.

20/ II-268.

21/ Tr. 14,431-57.

22/ See Ex. ST-19, p. II-268.

23/ Tr. 7892, 8007, 14,400, 14,457.

We thus agree with Judge Litt that additional care should be taken in the design of the terminal, so that it can at least withstand 20-foot waves, whether or not the berths are occupied. 24/

A comparable situation prevails on the California coast. Oxnard and Point Conception lie in an area where earthquakes are an almost routine occurrence. While the facility is clearly designed to withstand even a fairly major event (.6g bedrock acceleration) without a catastropic spill and possible major loss of life, the possibility of damage to the facilities, rendering them inoperable, cannot be ruled out. 25/ The facilities are designed to meet a quake causing .32g bedrock acceleration, though they contain enough safety factor that the tanks and pipes, though not the dock and trestle, should survive a .6g event. 26/

In short, each system is subject to at least conceivable damage from a seismic event, but only in the case of El Paso is such a possibility a matter of serious and continued concern. While it is always difficult to assess the probability of events with a frequency as low as that of earthquakes, even in active zones, it seems within the realm of reasonable possibility that an earthquake caused outage could temporarily interrupt service by the El Paso system. The FEIS states that in the next 30 years there is a 40% chance of an earthquake in Price William Sound equal to the 1964 event, and a 60% chance of a magnitude 8 quake. 27/

The evidence does not, however, support any great likelihood of the complete destruction of El Paso facilities by seismic activity.

24/ I.D. 107.

25/ See, e.g., ST-20, pp. 176-77; Tr. 24,917-19; 25,084-86.

26/ EP-65 at 3.4-4; WL-53, at 4-14.

27/ ST-22, II-106.

Two other possible dangers to the El Paso system should be noted. The first is from several active glaciers near the lower portion of the proposed route. 28/ While in general such glaciers are now retreating, and appear unlikely to advance again within the life of the project, at least one such glacier (Black Rapids) could be preparing to advance and could destroy several miles of the system should it move across the pipeline right-of-way. 29/

A second possible source of interruption is simple accumulation of routine defects and outages in component parts of the liquefaction, ship transportation, and regasification facilities. Many of these transportation matters are discussed in Chapter VII, and in Judge Litt's section on "El Paso-Cryogenic Tanker Fleet." 30/ El Paso recognizes the possibility of such problems, and includes approximately .5 days per round trip (11.31 days per trip without delays) for random delays and five days per year per train for unscheduled downtime in the LNG facility. 31/

However, delays or mishaps during any of a number of stages during El Paso's basic cycle could lead to a partial outage, in the sense that the full amount of LNG scheduled could not be lifted. Such occurrences would include prolonged outage of one or more gasification or liquefaction trains, or unscheduled extension of maintenance periods due to problems discovered.

Similarly, while the overall calculations set forth in Chapter VIII, above, confirm the ability of the interrelated El Paso system to transport the specified quantities of gas under the stated conditions, other incidents are certainly conceivable, and are indeed the everyday

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28/ FEIS, II-266-267.

29/ See Tr. 9301-9308.

30/ I.D. 137-159.

31/ Tr. 7762-65.

risks of industrial operation. This is especially true since El Paso's system requires much more labor than the others, and is thus exposed to greater risks of human error or labor dispute. Those risks are nowhere near as minimal as the probability of earthquakes sufficient to destroy totally the facilities. 32/

On the other hand, outages of this type are almost by their nature partial rather than total. Thus, the possibility of juggling other components of the El Paso system, or of obtaining supply from other sources in order to make up a partial shortfall, is quite good.

B. Soil Instability

A large amount of time has been spent by each applicant on possible dangers to pipeline construction and operation because of alteration in the existing soil characteristics by the introduction of a gas pipeline. Arctic soils are notable for their fragility, having developed under isolated conditions of extremes of temperature and climate. The major dangers are frost heave and thaw settlement. These terms denote conditions which are essentially the opposite of each other, and which derive from the simple physical principle that water occupies more space as it freezes, less as it melts.

In areas of continuous permafrost, the ground is generally frozen to a depth at least as great as that in which the pipeline is laid. Thus, the introduction of the pipeline at a temperature below 32°F. works no great transformation in the thermal regime. However, in areas where the ground is not frozen to that depth, and where free water may thus occur, such water can turn to ice or frost upon coming in contact with the chilled pipeline.

32/ See, e.g., WL-51, WL-53, quoted at I.D. 132, where scientific notation must be used to describe the smallest of certain risks.

Such an occurrence, occasioning what is known as a "frost bulb", then feeds upon itself, providing additional cold surface for the freezing of additional water, until a lens of ice can build up to the point that the pipeline may simply be pushed out of the ground.

Thaw settlement, on the other hand, occurs when a pipeline above 32°F. crosses an area of frozen ground, and the heat of the pipe causes the frost in the ground to melt and the land to subside. The temperature of each line will shift from below 32°F. to above 32°F. at some point along the line. Since each pipeline will originate in Prudhoe Bay, and cross areas of continuous and discontinuous permafrost, each will encounter these soil problems to greater or lesser degrees.

The Judge found that the Arctic route, which runs southeasterly, will traverse such potentially dangerous areas for a greater distance than will El Paso, which moves basically southward until clear of the permafrost areas. 33/

On the other hand, the exact amounts of affected soil are not clear from the record. 34/ Arctic goes through 250 miles of discontinuous permafrost. However, there is a risk of frost heave on only a portion of that distance. 35/ The El Paso route may encounter risk of frost heave for 100 miles, 36/ though El Paso says only 50 miles present serious concern. 37/ Alcan would have 80 to 105 miles of such problem areas, though staff says the distance may be up to 180 miles. 38/ In any event, from a realiability point of view, the problems are similar. If a line is not designed to withstand frost heave, it only takes one such location to break the pipe.

33/ I.D. 48, 111.

34/ See AP-13, pp. 31-36 and Fig. 3.1-1.

35/ Tr. 42,915; 25,502, Arctic Geotechnical Brief, p. 43.

36/ Tr. 25,302; 25,501.

37/ Geotechnical Brief, p. 21; Tr. 6331.

38/ Tr. 38,841; Ex. AP-5, Tab 14, at 6; Staff Geotechnical Reply Brief, at 19.

Arctic has now concluded that its original method of combating frost heave, essentially by piling weight on top of the pipe through deep burial and a berm, will not work. Recent refinements of its testing data and computer program indicate that ice would continue to build up beneath the pipe in spite of such measures. Arctic now proposes to prevent such build up by a combination of two measures: Insulation of the pipe itself, thus lessening the freezing effect caused by the pipe; and various types of electric heating to remove free water near susceptible areas of the pipeline.

Alcan attacks the feasibility of Arctic's new design, and also attacks the necessity for it. 39/ It argues that a correct computer model reveals that frost heave is simply not as serious a problem as Arctic considers it to be. While the evidence before us is not sufficient to make a definitive finding as to the appropriate amount of care necessary to guard against frost heave, 40/ we agree with Judge Litt that the problem can be solved with sufficient expenditure of design, time, and capital. 41/ Since the basics of the soil stability problem are common to all three systems, it seems clear that whichever system is chosen will draw on all the scientific and engineering knowledge available at the time construction begins.

We cannot give additional weight to Arctic's proposal for devising a means to defeat frost heave, since Alcan or El Paso could use the same technology. Similarly, no advantage can be given to Alcan if later information shows that frost heave would not be a serious problem. In this case, Arctic could simply omit its additional and costly facilities should later research show that Alcan was correct.

39/ Presented as document No. 20 of its March 22, 1977, submittal to the Commission, amplified in Alcan's April 8, 1977, Response to Arctic Gas Submittals, Appendix C.

40/ See Staff Report, April 8, 1977, pp. 53-54.

41/ See, *e.g.*, I.D., 112.

The problem of thaw settlement is generally better understood than frost heave, as pipelines above the freezing point of water have been operated in areas of discontinuous permafrost in the past. Here again, we have differences in the mileage of pipeline exposed to the problem, and in the means proposed to deal with it.

El Paso plans to chill its line below 32°F. until the line is south of any general permafrost area. Alcan will chill its gas until it reaches the Canadian border and for 41 miles thereafter, by which time very little, if any, permafrost should remain. Air coolers will also be used at later stations. 42/

Arctic may encounter thaw settlement problems for about 220 miles in Northern Alberta and the Northwest Territories. Each of the applicants proposes to use special ditching techniques where thaw settlement may be a problem, replacing native soil with gravel or other materials not susceptible to settlement. Arctic proposes an additional measure in areas where settlement may exceed three feet, burying the pipe attached to pile supports, which would be driven deep into unfrozen material. 43/ The use of such supports, comparable to the Vertical Support Members used on the Alyeska line, is a proven technology, and should pose no additional reliability problems.

In summary, we find that each applicant can construct a line that will operate with adequate reliability against the problems caused by soil conditions. As final engineering is done, adequate design can be developed from the work already completed. In addition, the use of thermistors (sensing devices) at any critical suspected problem areas ultimately located would give notice of changing conditions in the

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42/ See Figures 3 and 4, Alcan 48- Inch Alternative submittal; Staff Report, April 8, 1977, p. 12.

43/ Staff Report, supra, pp. 48-50.

buried system far in advance of surface indications. With even the best of systems and construction, some problems will occur during the life of the project. These can best be handled on an individual basis with localized treatment.

C. Metallurgy

The question addressed in this section is the possibility of failure during normal operation of the pipe used in the system. El Paso and Arctic propose to operate at the extremely high pressure of 1680 psig, while Alcan's new 48-inch alternative will operate at 1260 psig. While commercial operation at such pressures has not heretofore occurred, it does not appear to be beyond the state of the art.

As El Paso's line will be only 42-inch, a size now in use elsewhere, it has come under little attack in these proceedings, though it will operate at the same high pressure as Arctic. Arctic's use of X-70 (70,000 pounds per square inch strength) pipe, a quality not previously the subject of a rulemaking proceeding for DOT approval, 44 / has been heavily attacked. Alcan contends that its own design, using a lower pressure, and steel characterized by a high Charpy toughness (a measure of metal resistance to fracture), is a more reliable design. 45 /

The basic argument here concerns resistance to ductile fracture, and means of stopping a fracture, once started. Arctic plans to use pipe designed not to break on any defect up to 6.5 inches long, and to use crack arrestors (tight fitting metal sleeves) to prevent any fracture from continuing for more than 300 feet. We agree with the Judge's weighing of the conflicting evidence on crack arrestors, 46 / and find them to be a useful, though not foolproof, addition to Arctic's system.

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44 / Tr. 3,378-79

45 / Tr. 38,633; 38,760-765.

46 / I.D. 51-52. The Department of Transportation has questioned whether the crack arrestors would interfere with the cathodic protection of the pipi. DOT comments on initial decision, pp. 2-3. This issue should be explored further.

Alcan states that its system is designed for 1440 psig, but will actually operate at only 1250. Alcan insists that this design is conservative and will mean that it operates at only 67 percent of SMYS (Specified Minimum Yield Strength). Arctic notes that in Canada this stress would be over 69 percent. 47 / Arctic, on the other hand, would operate in the United States at 72 percent of SMYS, though Canadian regulations will allow it to operate at 80 percent. 48 / El Paso would operate at 72 percent of SMYS.

While we find that Arctic's current design runs closer to the frontiers of technology, the differences in projected reliability between it and Alcan are not sufficient to make a major distinction between the two. We can assume that whatever system is chosen will have access to the best metallurgy then available.

We therefore find that none of the competing applicants has a clear advantage as to the basic metallurgy of its structure, but that continued care and testing will be required.

D. LNG Safety and Siting

LNG has several properties which make it a uniquely dangerous cargo. Because of its liquid nature, and the ratio of approximately 600 to 1 between gas volumes and liquid volumes, the possibility always exists that a spill of LNG could create an enormous gas cloud with at least some potentiality for damage to human life through combustion or asphyxiation. This subject is handled comprehensively in risk analyses made by SAI (Science Applications, Inc.) for Western LNG 49 / and in the Staff FEIS, 50 / which are

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47 / Alcan Geotechnical Brief, p. 27; Arctic Geotechnical Reply Brief, pp. 27-28; Tr. 38,722-760.

48 / Tr. 28,421; 28,447.

49 / Exs. WL-51, WL-53.

50 / Appendix C, III-404, *et seq.*

included in the record of these proceedings. They indicate that an absolutely worst case LNG disaster, while extremely unlikely, could generate extremely high casualties if it occurred near a populated area. The SAI study indicates that 113,000 fatalities at Oxnard is the theoretical maximum. However, such an event might occur only once every 100,000,000,000,000,000,000,000,000,000,000,000,000,000,000,000,000,000,000,000 years, many times longer than the age of the universe. An accident that might kill anyone on shore might occur once every 1,000,000 years. 51 /

LNG is being handled both on land and sea in a large and increasing number of areas, with no loss of life due to an LNG-caused catastrophe occurring in the last 30 years. It is true that in 1944, 133 people were killed in an LNG accident caused by the collapse of a fairly flimsy tank, surrounded by an inadequate dike, in Cleveland, Ohio.

The risk analyses, while indicating the extreme unlikelihood of such an event, do bring home the fact that LNG is an extremely volatile substance which lends its own dangers of service interruption. Ordinary natural gas, rushing from a broken pipeline, whether or not ignited, also contain enormous potential for destruction. 52/

In summary, we find some advantage in basic conceptual reliability of conventional buried pipelines over an LNG mode of transportation. While the LNG system runs a miniscule chance of a major catastrophe, its more basic difficulty is the series of steps necessary for complete transportation, any one of which could be a trouble spot. Of course, even normal buried pipelines fail at a rate of about one break

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51/ Ex. WL-51, p. 8-169.

52/ See, e.g., Iroquois analysis (ST-51), p. 170, and Appendix E, showing the enormous thrusts and velocities created by a simple pipeline rupture.

per 13,000 miles per year, in the lower 48. 53/ The novel technology and harsh conditions of the Alaskan Gas projects might be expected to increase these chances, but the absence of other construction activities should greatly reduce them.

These possible dangers make the selection of the best possible site for the liquefaction and gasification facilities critical. On the Alaskan coast, the Gravina Point facility is favored by El Paso, and basically by the other parties involved, with the exception of Staff. Staff has advanced the alternative of a facility at Cape Starichkof, primarily because of its alleged cost and environmental advantages. 54/ Staff continues to press this alternative, although recognizing that it is unable to demonstrate convincingly its superiority. Staff argues that further investigation is needed before a firm decision can be made. We basically agree.

We find that either location could probably provide an acceptable liquefaction facility. Until considerable additional work is done, however, we would not be able to specify with confidence the exact means for optimum terminal construction. Should El Paso be chosen, the selection and construction of the liquefaction facility will not create great time pressure. We believe that the President and Congress should examine the considerations set forth below and, should El Paso be chosen, either come to an independent conclusion based on those factors, or provide for a site-specific proceeding to choose the terminal.

El Paso's original cost data indicates an additional expense of some $170 million to carry the pipeline to Gravina as opposed to Starichkof. 55/ Because of the exceptionally rugged nature of the Chugach Mountain Range through which the pipeline must pass to reach Gravina, it is certainly conceivable that this amount could increase.

53/ Tr. 28,081.

54/ See ST-19, II-495 to II-502.

55/ Tr. 23,185.

On the other hand, the location of Starichkof means that the trade route distance from Point Conception would be extended by some 170 miles, 56 / which would itself create greater costs, and a certain degree of greater unreliability by stretching the already tight El Paso schedules. The basic area around Starichkof, while still within the general Alaskan earthquake belt, displays a possible seismicity of only about 7.5, instead of the 8.5 possible at Gravina. 57 / While technically not a wilderness area, Gravina Point, and the Chugach National Forest through which a pipeline must pass, represent largely unspoiled lands, and in the case of the Chugach, truly formidable terrain for construction. 57a/

At Starichkof, on the other hand, some development of a minor nature has already begun, and access lies either through a corridor already developed (the rail belt on the north side of Cook Inlet), or through relatively easy topography on the south side of Cook Inlet. The Starichkof alternative would require the crossing of miles of open water at Cook Inlet, but this does not appear to be a task beyond current technology.

The leading argument against Starichkof is the navigational hazard presented by winter ice in the upper reaches of Cook Inlet. 58/ There is considerable evidence that at Nikiski, some 50 miles to the north, ice has been a frequent, though not insurmountable, problem. It has damaged some older ships, and from time to time halted loading at an existing LNG plant. Although Starichkof is further to the south, some ice may still be present in this area in colder winters. There is enough evidence to indicate that at the very least there is a potential for additional delay during colder than normal winters, a delay which itself adds to the cost and unreliability of the system. On balance, we

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56/ I.D. 122; Tr. 23,088-89.

57/ See ST-19, II-509. The Richter scale is logarithmic, so an event of magnitude 8 is ten times as intense as one of magnitude 7.

57a/ See I.D. 191-2; Tr. 8953.

58/ See I.D. 123, ST-38B.

believe it has been shown that Gravina would be an acceptable terminal for this project, and that Starichkof has not yet been shown to be.

However, we urge the President and Congress to carefully consider the above factors, especially the environmental preferability, and possible cost savings of Starichkof. The Commission was not able to secure a definitive opinion from the Coast Guard, the ultimate arbiters of navigational decisions, on the absolute impact of the ice situation. Should the President and Congress, and/or the Coast Guard, determine that year-round navigation is not feasible at Starichkof with the safety and reliability desired, then Gravina should be chosen as the location for an El Paso facility.

But, if the ice question remains open or is resolved in favor of navigation, then serious consideration should be given to Starichkof on environmental and cost grounds. Such a determination could be made directly by the President and Congress, or it could be deferred for a later hearing. We find that Gravina would be an acceptable terminal location, and that if the ice question can be satisfactorily resolved, Starichkof would be as well.

A similar contest occurs over the California facilities. El Paso has proposed to use Point Conception, an area now essentially undeveloped, while staff prefers a terminal at Oxnard, in a developing industrial area. The basic reason for supporting Point Conception is that it is some 70 miles closer to Alaska, thus reducing both the operating costs and outage possibilities compared to a location further south. Its very inaccessibility and remoteness in one sense minimizes dangers and impacts on people, since almost no one lives nearby.

The choice of this site, however, would cause the construction of facilities on land otherwise lightly used, thus spoiling that portion of the environment, and inviting further development.

Both facilities are in high-risk earthquake zones, 59/ but El Paso's design, which it contends and we find would be adequate for Point Conception, could be equally adequate if installed at Oxnard. We note that the State of California, through its Public Utility Commission filed a Brief supporting Oxnard, though at least two California State agencies did not agree.

This portion of the proceedings is to some extent bound up with the Commission's consideration of two other LNG projects, one from Indonesia and one from southern Alaska. Staff here proposes that all facilities be concentrated at Oxnard, while Western LNG Corporation, the operator of the terminals, seeks the certification of three different facilities to handle the three projects. Western LNG argues that having multiple facilities will insure greater reliability in that an accident or disaster at one facility would affect only that facility, leaving the others undisturbed.

On the other hand, the multiple terminal operation does impose considerably greater capital costs (in the range of one-half billion dollars), and unavoidably causes greater impact on the environment. We believe the prospects of major catastrophe to be sufficiently remote that little weight should be given to providing additional protection against such events through dispersed terminals. The sites are close enough together that a truly major catastrophe, such as a devastating earthquake or ocean storm could affect more than one of the terminals. Finally, the possibility of accidents which would affect a particular loading berth, gasification train, or storage tank, would be approximately the same whether concentrated at one location or spread out along various miles of coast line.

We also believe that the possible synergistic effects of LNG facilities in an already industrialized area favor Oxnard. Increasing attention is being given to the appropriate use of heat which is added or subtracted to materials for other purposes. By the liquefaction process, for which

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59/ See WL-14, pp. 2-19, 2-27, 2-29.

energy must be expended in Alaska in any event, the LNG tankers have in essence become a free source of cooling power, which could be better used in an industrial process than in cooling the Pacific. While we cannot necessarily foresee every use that might be made of this resource, it seems clear that the potential for its development is greater within an already industrialized area than in a rural and remote one.

On balance, on geotechnical, reliability and environmental grounds, we find Oxnard preferable and that it should be certificated as the terminal for this project, if El Paso is chosen.

We make no finding on the ultimate question of whether there should be a single, or multiple West Coast terminals. That question can be addressed again when the Pac-Alaska and Pac-Indonesia cases are decided.

E. Consequences of Failure, and Repair

A final aspect of reliability is the magnitude of the possible consequences of a failure, and the time necessary to make repairs. For a pipeline outage on any of the systems, repair would normally be fairly rapid. Shut-off valves would stop the flow of gas through the affected areas, and repair crews could quickly replace the damaged section and place the system back in operation. 60/

This is true, however, only if the pipeline is accessible. The Alcan system, with accessibility from all-weather roads or existing utility corridors, is superior in this respect. 61/ The El Paso pipeline would have comparable advantages, with the possible exception of a route through the Chugach Mountains, which could be inaccessible due to fog or winter weather conditions for several days at a time. Repair or replacement of a damaged or destroyed ship could take much longer.

60/ See EP-231, p. 142; Tr. 28,141-154.

61/ See Tr. 6309.

The Arctic project presents a somewhat different problem, in that under non-winter conditions, accessibility might be limited by tundra regulations and environmental considerations. Arctic indicates that by use of helicopters and low ground pressure (LGP) vehicles, sufficient access could be maintained so that repairs could be accomplished within a timeframe comparable to other pipelines. 62/

The one area in which this would not be true involves the underwater crossing of Shallow Bay, at the mouth of the Mackenzie. Here, it is obvious, and Arctic admits, that the buried pipeline could be completely inaccessible for up to six weeks during the spring ice break-up and high water season. This inaccessibility would be at a period of lessened demand in the lower 48, and the 2-3 week period of inaccessibility during the October freeze-up could be of greater concern. 63/ For this reason, twin 36-inch pipelines will be laid under Shallow Bay. Additional compression would provide the means for either section to deliver the full flow of the line for some time. We find this solution to be adequate, in that evidence shows that failure of both sections of the pipeline is a likelihood so remote as not to figure in the calculations. 64/

Finally, we note that under either overland system, gas would basically be delivered into the general pipeline system of the United States. Since the gas from any of these projects, even at the most optimistic, would comprise less than 10 percent of total national supply, the basic integrity of the pipeline system of the country would not be threatened by an abrupt termination of the Alaska supply. The case with the El Paso system is somewhat different. With the movement of Alaskan gas to other parts of the

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62/ Tr. 28,081-28,083.

63/ Tr. 15,350-52; 15,567-68.

64/ Tr. 15,521-23.

country by displacement, the historical flow of gas from the Permian Basin to California would be substantially reduced. The vast majority of the gas upon which California depends (physically, but not fiscally) would be coming off the ships at the Western LNG terminal. Any outage in El Paso's service would allow California only a short time to secure additional supplies from other sources. El Paso will have the ability to resume the flow of gas from the Permian to California within eight hours after notice. 65/

Of course, the warning time of such an event would vary depending on where it occurred. Thus, a break in the Alaskan land pipeline might not be reflected in California for more than a week. An event which might disable the LNG plant in Alaska would be felt within five days, and any tanker accident would in all likelihood affect only a small proportion of the waterborne flow.

The serious danger of short-run outages lies in damage to the regasification facilities, or to the storage tanks and exiting pipeline. Damage to these facilities could mean that gas supply into the California system would be cut off almost instantaneously, and the reserves available to the companies would be limited to what was actually in their lines at the time, plus such storage as could be activated rapidly.

The likelihood of a total regasification system collapse appears to be very minimal. But even in that event, with absolutely minimal reaction time, the gas in the distributors' facilities, plus the amount of Canadian and California gas which exists, should make it possible for the system to continue to operate, at least at a minimum emergency level, until the Permian Basin flow could be restored. This scenario is, of course, not fool proof, and does lead to the conclusion that the concentrated impact of the El Paso project on one area of the United States must be counted as a minus for this proposal.

65/ Under any of the displacement schemes proposed, the original owners of displaced gas do not give up their contractual rights to that gas. Thus, if there were an Alaskan gas system interruption, California purchasers would still have their contractual rights to gas from other areas such as the Permian Basin.

F. Summary

Each of the proposed systems contains many facets which cannot be said, at this time, to be guaranteed to operate reliably. However, the same statement could have been made, six to seven years in advance of completion, of almost any large-scale project on which our Nation now relies. Our examination of the evidence leads us to conclude that it is highly probable that each of the three systems can, upon completion, be operated with a reliability acceptable to the natural gas customers of the United States.

CHAPTER VIII

CONSTRUCTION COSTS AND SCHEDULING

The cost estimates submitted to the Federal Power Commission for all applicants are expressed in 1975 dollars. Obviously, even constant dollar cost estimates are subject to direct increase or "cost overrun" resulting either from unforeseen difficulties in construction or optimistic underestimation. None of the proposals is free from some risk of cost overrun from either source. With projects of this magnitude any potential for delay, particularly late in the project, significantly affects costs because the accumulating allowance for funds used during construction increases the rate base.

Because of the complexity and unusual challenges these projects face, estimates vary widely, even among experts, as to the cost and difficulty of performing any given task. An Arctic witness, Mr. Franks, said that he would not be surprised or bothered by a variance in estimates of pipeline installation costs in Alaska of one third. 1/

The capital costs and the cost of service of any system vary with the volumes of natural gas to be transported. Since the precise volumes of gas that will be produced from known reserves, much less undiscovered reserves, cannot be established at this time, the three applicants placed in evidence the costs of low volume and high volume cases. They neither agreed upon nor had imposed upon them a uniform definition for either case. The result is three different assumptions of the amount of reserves to be produced from the Prudhoe Bay field. A single figure for volume, even if incorrect, would make comparison of construction costs more meaningful. Such a common denominator is not available.

We have determined that the most probable range of volumes of gas that will be delivered from the Prudhoe Bay field is 2.0 to 2.5 Bcfd. Therefore, comparative

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1/ T. 171/28,267.

capital cost estimates are stated for each applicant's low case within that range. They are:

Arctic	2.25 Bcfd 2/
El Paso	2.3614 Bcfd
Alcan	2.4 Bcfd

Estimated Capital Costs, Including AFUDC
(Millions of 1975 Dollars)

Arctic	Per Arctic 3/	Per Alcan 4/
Alaskan Arctic	$ 657.7	902.7
Canadian Arctic	5,749.8 5/	6,593.9
Alberta Natural	53.1	53.1
Pacific Gas Transmission	254.8	254.8
Pacific Gas & Electric	335.0 6/	335.0 6/
Northern Border	1,096.7	1,096.7
	8,147.1	9,236.2
Less Allocation to Canada	(1,418.6)	(2,123.9) 7/
	6,728.5	7,112.3 7/

2/ Arctic also would transport natural gas from the Mackenzie Delta. We have determined that the volumes from that area are not likely to exceed 1.0 Bcfd in the foreseeable future. Ch. III, supra. The capital costs set out here are from the Arctic "No Expansion" case and assume 1.0 Bcfd from the Mackenzie Delta.

3/ April 4, 1977.

4/ Each applicant costed the project of the others. The latest such estimates are included to illustrate that even the opposition's estimates are not so high as to make the projects economically unattractive.

5/ Does not include an "allowance for phasing" of $322 million that adjusts for the earlier commencement of deliveries from Mackenzie Delta.

6/ Prior estimates were $285.5 million for PG&E facilities. Arctic's April 4, 1977, filing shows $335.0 million to account for additions in the final "western leg" proposal. Approximately that amount, $343.5 million, is contained in our cost of service programs for the western leg. We here use the Arctic statement for illustrative purposes.

7/ Alcan Response April 8, 1977, App. B. This estimate uses an erroneous allocation factor for Canadian Arctic. It should be 24.67 percent rather than the inferred 32.2 percent.

El Paso	Per El Paso 8/		Per Arctic
Alaska Pipeline	$ 2,203.8)		$ 2,141.8
Alaska LNG Plant	1,625.1)	9/	1,502.2
Alaska Marine Terminal	91.8)		
LNG Tankers	1,614.2		1,401.0
California Regas Plant	401.1		613.2
California Pipelines	305.1		
EOC Pipelines	329.7		257.6
Total	6,570.8		5,915.8
		AFUDC	1,536.0
		Total	7,451.8

Alcan	Per Alcan 10/	Per Arctic
Alaska	$ 2,445.5	$ 2,622.2
Foothills (Yukon)	1,119.4	1,408.3
Westcoast	828.5	891.6
AGTL (Canada)	681.3	963.7
Pacific Gas Transmission	254.8	254.8
Pacific Gas & Electric	335.0	335.0
Northern Border	1,096.7	1,096.7
Total	6,761.2	7,541.1

Excluding AFUDC, the dollar outlays projected by each applicant for its own project are as follows:

Arctic 11/	$5,620.5
El Paso	$5,587.5
Alcan	$5,780.9

8/ March 1, 1977.

9/ The estimated total construction cost (including AFUDC) for the El Paso facilities in Alaska is $4,447 million. However, revenues earned in the testing and start-up period are capitalized by El Paso with the result that the value of plant in-service for rate base purposes is $3,920.6. Ex. EP-227, Sch. 3, line 7.

10/ March 22, 1977.

11/ These costs are 100 percent of the facilities carrying only U.S. gas, and 75.33 percent of the facilities carrying both U.S. and Canadian gas.

I. Arctic

A. Construction Plan and Costs

1. General

Arctic proposes to commence mainline construction in the winter of the fourth of a six-year schedule. This is currently projected to be October or November of 1980. Nine spreads 12/ (A-I) are expected to operate between Tununuk Junction and a point approximately 75 miles north of Caroline Junction. Each spread is charged with completing between 70 and 82 miles of 48-inch pipeline during this first winter. In the second winter, each spread constructs a similar amount of adjacent line. In the preceding and succeeding summers, Spreads H and I move to the south to construct the 42-inch line from Caroline Junction to Monchy and the 30-inch line to the "Western Leg." 13/

In the final winter, six spreads (A-F) are scheduled to move to the North Slope and complete the section between Prudhoe Bay and Tununuk Junction.

Arctic has conducted extensive pre-construction research and development. It has studied for several years the problems of pipeline construction in the Northern latitudes. It has engaged experienced contractors and personnel to develop the construction programs and cost estimates. The Arctic plan involves, however, more winter construction at higher latitudes, where the margin for slippage or error is slim, than does El Paso or Alcan. The risks in that environment affect both the direct costs of performing a function and the time within which that function can be performed.

12/ A "spread" is an integrated construction crew of several hundred persons (750-800 in case of Arctic) that is responsible for a section of the line.

13/ The Brief on Exceptions of Sierra Club, *et al.*, p. 18, states that Arctic will use summer construction in Spreads E through I, referring to Arctic Environmental Report, Ch. II, Section F, Figure II F-7. However, that was superseded by Ex. AA-83 which shows winter construction as described above.

Winter construction in the sensitive permafrost areas of the Arctic offers the best way of minimizing the impact of the construction activity in that environment. The surface of the ground is frozen and, if a proper base is prepared, scarring of the tundra will be minimal. After the trench is cut, there is no risk of thawing of the sides or bottom and the width of ground disturbance is minimized. Consequently, Arctic plans winter construction for the entire route north of a point about 75 miles above Caroline Junction. The price for winter construction is exposure to the extreme weather conditions -- high winds and cold, wind-chill factors at times below -100 degrees F., and prolonged darkness. Many attempts have been made to work in that environment -- some successful, others not. The successful efforts include construction of several hundred miles of pipeline in Canada 14/ and the construction of the extensive gathering system at Prudhoe Bay. 15/ In the latter case, work continued through darkness and temperatures down to -40 degrees F. Some decline in productivity was compensated for with additional personnel. Obviously, these projects are not close in magnitude to the Arctic project. However, Arctic believes, through advance planning, that it can continue work until the wind chill factor reaches -45 degrees F. It intends to provide adequate shelters for laborers and has designed a movable shelter for welding crews which will maintain internal temperatures at approximately 20 degrees F. In addition, Arctic has allowed substantial numbers of nonworking days in its schedule to allow for vacations and extreme weather conditions.

On balance, we believe that the evidence warrants a conclusion that winter construction in the high Arctic is feasible and that Arctic has presented a reasonable program for its execution.

14/ See T. 202/34,514-526, 34,548-556.

15/ T. 202/34,541-47. The extensive equipment modifications that are required for Arctic conditions are described at T. 202/34,527-540.

2. Snow Roads and Work Pads

In its initial application, El Paso states:

> "Winter construction makes it feasible to provide a compacted snow pad as a working surface on the pipeline right-of-way. Snow fences will be erected along the right-of-way to capture snow for this purpose. Also, the snow can be supplemented by spraying water over these filler materials and allowing it to freeze or artificial snow can be provided using snow machines." 16/

Yet, El Paso and others challenge the Arctic plan to use snow roads and work pads for most sections of the pipeline above the 65th parallel. They argue that there is not sufficient snow cover in most areas, that it is impractical to harvest enough snow, that there is insufficient water in some areas to make artificial snow, that snow roads and work pads do not have sufficient durability, and that Arctic has provided inadequate funding for their construction or maintenance.

Arctic intends to rely upon snow roads and work pads to a far greater extent than anyone heretofore. The Arctic plan is novel, but not necessarily infeasible. Arctic has conducted the most extensive tests to date of the construction and maintenance of snow roads. The test program was successful. 17/ Also, snow work pads were used successfully along most of the 160-mile Alyeska fuel-gas pipeline. 18/ The evidence establishes that snow in the Northern latitudes can provide a surface with suitable stability and integrity for movement of vehicles and machinery with minimal impact on the permafrost. Judge Litt so found after giving extensive consideration to the issue. 19/ We agree with that finding.

16/ El Paso, Application for Certificate, Vol. III, §1.5, Construction Procedures, p. 10.

17/ See Ex. AA-19.

18/ T. 193/32,592-96.

19/ I.D. 67-83.

In our view, the most substantial issue is whether sufficient snow will be available from in-place ground cover, harvesting, or manufacture. There has been extensive testimony on this issue and general agreement that natural snowfall is likely to be light, particularly on the North Slope. Extensive manufacture of snow may be required. El Paso challenges the feasibility of snow manufacture and describes Arctic's snow machines as "conceptual." 20/ But El Paso's criticism refers only to the proposed "super" snowmaker. The techniques of snow manufacture with smaller equipment, which Arctic can use, are well developed, as any Eastern ski slope operator can testify. The ultimate issue is whether sufficient water is available at an environmentally acceptable cost to make enough snow. 21/ Both Arctic 22/ and El Paso 23/ commissioned water availability studies on the North Slope area and, not surprisingly, reached somewhat different conclusions. However, El Paso restricted its study to lakes 2,000 feet or more in one dimension, giving as its reason that smaller lakes would be frozen to the bottom at some time during the winter. However, since most of the water needs would exist in October and November, those lakes should be available for withdrawal during at least part of that period.

The Arctic study was not so limited. It specified a total water need of 8,222,000 barrels for the North Slope construction between Prudhoe Bay and Tununuk Junction. This amount constituted slightly over 1 percent of the total lake water 24/ and less than a two-day flow of the springs. For the most part, the study reflected only water sources within 5 miles of the pipeline route.

20/ El Paso, Brief on Exceptions, p. 29.

21/ Conservation Intervenors, Brief on Exceptions, p. 17.

22/ Ex. AA-43.

23/ Ex. EP-238.

24/ The Draft Terms and Conditions would limit withdrawal from a lake to 5 percent of available water. Chapter III, *infra*.

Six million barrels of water were specified for snow road and work pad construction. A snow road 30 feet wide by 18 inches deep requires 21,000 barrels per mile and a snow work pad 90 feet wide by 9 inches deep requires 32,000 barrels per mile. 25/ A 12-inch deep work pad would require approximately 43,000 barrels per mile. Thus, with a constant 12-inch work pad, Arctic projected water needs sufficient for more than 95 miles 26/ each of snow road and work pad which would consume a minute portion of the total supply and the area.

The most critical area in terms of water availability is eastern Alaska between MP70 and MP190, where Arctic must rely principally upon springs. Springs have the most abundant fish population and extreme care must be taken in water withdrawal to avoid harm to the fish or their habitat. The State of Alaska apparently will control the water withdrawal on the North Slope and will specify environmentally acceptable locations and rates of withdrawal. Within these restraints, it appears that sufficient water will be available within reasonable distance of the right-of-way and, in the extreme, more than ample supplies are available with longer hauls.

We believe that Arctic has established a reasonable margin of water availability adequate to respond to the risk of inadequate natural snowfall on the North Slope.

3. Productivity

The most critical element of pipelaying productivity along the Arctic route will be the rate of welding. The most critical weld is "root pass" or "stringer bead," which initially joins the pipe sections. Until the root pass is completed, the alignment clamp cannot be moved to the next joint.

25/ T. 163/28,863.

26/ A total of 336 miles of right-of-way were surveyed.

Arctic plans to lay pipe on the North Slope at the rate of .71 miles per spread per working day. With 80-foot lengths of pipe, about 50 welds per day will be required. 27/ In laboratory conditions, stringer bead welders can deposit up to 3-1/2 pounds of metal per hour. Four stringer bead welders can work on a single pipe and deposit more than 12 pounds per hour or 120 pounds of metal per 10-hour day. A stringer bead on a 48-inch diameter pipe requires about 1 pound of metal. Thus, in theory, up to 120 joints per day could be produced. 28/ The Arctic Gas welders would be required to operate at only 42 percent of that rate to meet the goal. Arctic Gas' 48-inch x .720 pipe will require several fill-pass welds which require much larger quantities of metal overall, but since multiple fill-pass crews can operate simultaneously behind the stringer bead, the fill-pass welding does not significantly restrict productivity.

El Paso argued that data from the experiences in Alaska disproves the Arctic estimates. Principal focus was upon the welding productivity achieved by the crews that assembled the gathering facilities at the Prudhoe Bay field. Judge Litt attached little weight to such productivity data on the basis that it was "piece work" that had little relation to continuous mainline construction. We agree. Further, the Alyeska contractors, including El Paso's witness, Green Construction Co., achieved in the year 1976, a calendar day average rate comparable to that proposed by Arctic Gas. 29/ While Green's welding was done in summer weather, the Alyeska

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27/ Arctic states that each spread will be sized to have the capability of laying one mile or about 70 joints per day which was reduced to .71 miles for the North Slope through judgment, T. 203/34,802.

28/ Provided that the alignment clamp may be removed upon completion of the stringer bead.

29/ T. 183/30,848. The 48-inch Alyeska pipe has a wall thickness of about 1/2 inch versus .720 inch for the Arctic pipe. However, wall thickness affects the number of fill passes required, not the critical stringer bead pass.

pipeline involved some construction in mountains and frequent change from above ground to below ground which tends to slow productivity.

Finally, El Paso pointed out that the Arctic witness, Mr. Franks, used a productivity of .33 miles per day in estimating the cost of the El Paso system in Alaska, the same as estimated by El Paso. 30/ The inference El Paso would like to have drawn is that Arctic can achieve no better on its route. However, we do not believe the analogy is apt. The Arctic route in Alaska is across virtually flat, occasionally rolling, tundra. The El Paso route crosses the Brooks Range of mountains, including the narrow Atigun pass, several lesser mountain ranges, and the rugged Chugach Forest. In the relatively more level area south of Fairbanks, El Paso projects productivity essentially as high as that projected by Arctic. 31/

Arctic concludes by stating that if its projected productivity were threatened for the final critical winter on the North Slope, it could add two more spreads to the final winter construction program. The equipment from Spread G, which is scheduled to finish in Canada the preceding winter, could be moved up the Mackenzie River in the summer of year 5 and mobilized for construction in Canada at a cost of $48.2 million. 32/ An additional spread could be mobilized in Alaska at a cost of $70.4 million. 33/ Finally, in an emergency, Spreads H and I could be available for a portion of the winter after a "very difficult and expensive" move through Alaska. 34/

30/ El Paso, Brief on Exceptions, pp. 17, 46.

31/ El Paso, Application for Certificate, VIII, pp. 1.5-6.

32/ T. 233/40,549.

33/ Ibid.

34/ T. 202/34,589.

We find that the productivity rate proposed by Arctic Gas is reasonably achievable, and that corrective measures are available with infusion of more men, machines, and money should unexpected problems arise. 35/

4. Trench Excavation

Arctic requires excavation of a trench 8 feet wide and 12 feet deep. No continuous trenching machine now in production will excavate a trench that size. The largest machine available today is a Bannister 710 (7 by 10 feet trench). The 812 ditcher (quickly dubbed "super ditcher") which Arctic intends to use is still in the design phase. Critical tooth design tests have been conducted and basic engineering and design work has been done but no prototype has been tested. Thus, there is uncertainty as to the availability and performance of the machine. Arctic relies upon the super ditcher to reduce the amount of trench that must be drilled and shot (blasted), for example, from an estimated 26 percent on the North Slope to about 13 percent. 36/ It was estimated that the cost of excavation would be $60,000 per mile when blasting is required and half that where trenchers could be used. 37/

Alcan in the April 8, 1977 filing asserts that drilling and blasting will be required over 75 percent of the "northern portion of the Arctic route." This estimate is merely an assertion -- with no evidence to support it.

El Paso continually has stated that Arctic under-estimated the personnel required for blasting by seven-fold,

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35/ If the additional spreads were mobilized on the North Slope at a total cost of $120 million, the cost of service for Arctic would increase by less than 2 cents per Mcf.

36/ T. 202/34,566.

37/ I.D. 65.

i.e., 71 rather than 10 workers will be required. 38/ However, Arctic states that its early estimation of 10 per spread is an average for all areas -- and that 25 per spread were provided for the North Slope. 39/ In any event, Arctic stands ready to provide such additional personnel as local conditions dictate at relatively small additional cost. 40/ The production of trench excavation overall can maintain the pace of welding whether or not the "super ditcher" is used and, therefore, is not a critical element with respect to construction scheduling.

5. Logistics

El Paso contends that Arctic Gas understated by a factor of 23 the need for transporting of men and material by air. However, Arctic places principal reliance upon summer barging of non-perishable materials on the Hay and Mackenzie Rivers and from Seattle to the North Slope. Judge Litt found the barging plan feasible with proper planning, and that unanticipated late ice breakup or early freeze-up could be compensated for by more expensive but available ground transportation. Air transportation is planned basically for personnel, perishable goods, and essential parts. The vast fleet of aircraft protrayed by the El Paso witness will not be required.

6. Summary

In conclusion, we believe that the cost estimates submitted by Arctic are reasonably reliable. Modifications in the estimates were made during the course of the hearing to take account of deficiencies pointed up in cross-examination.

38/ El Paso, Brief on Exceptions, p. 40.

39/ T. 202/34,565-66.

40/ If blasting requirements were doubled along the entire route, the implied cost increase would be about $10,000,000, which would have insignificant impact on cost of service.

However, the cost estimates inherently cannot take into account the full measure of risk in a project. We believe it likely that Arctic will, in the final analysis, be required to expend greater resources on the critical North Slope sections. Whether or not it will take the precise form of additional spreads or larger work crews to provide an insurance against schedule slippage, we cannot now know. But some additional expenditures are likely. Therefore, we believe it highly probable that Arctic's costs would have to be increased by 7 to 10 percent on the North Slope. There also is a high probability of additional expenditures on the extreme northern sections of the mainline in Canada, e.g., north of the Norman Wells area. We thus assign to Arctic a high probability of direct cost increases in the range of 5 percent for the overall system resulting essentially from the risk of more severe than normal weather conditions.

B. Construction Schedule

Arctic's construction schedule places heavy reliance on the assumption that weather will not depart too far from normal warmth in the fall or spring, or normal cold in the winter. In all permafrost areas, transportation and construction will occur on snow roads and snow work pads to minimize impact on the tundra. While Arctic proposes construction on a scale not before experienced in such conditions, it has also planned and experimented on an unprecedented scale.

Whether Arctic can reasonably meet its construction schedule was addressed extensively by Alcan and El Paso. El Paso conducted the most extensive analysis through its witnesses from the Green Construction Company. In addition, El Paso commissioned the development of a stochastic model that purports to simulate the Arctic construction program. El Paso complains on exceptions that Judge Litt improperly ignored this risk analysis. 41/ We have, therefore, examined

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41/ El Paso, Brief on Exceptions, p. 110.

in some detail this analysis of the critical variables which could cause delay in the Arctic proposal.

The model El Paso used has basically five variables:

-- Length of the construction season

-- Productivity of welding and laying pipe

-- Rate of building snow roads

-- Rate of moving camps

-- Rate of constructing camps

The El Paso witnesses established or assumed probabilistic distributions and parameters for each of these factors. A computer sequenced the construction activities using randomly selected values from within the parameters. The model was run up to 1,000 times and the degree of probability of completion of construction at any of several dates was estimated. However, the model can yield realistic results only if the input variables are realistic. Thus, before evaluating the results of that simulation, we must examine the quality of its inputs.

1. Length of Construction Season

The winter construction season is directly dependent upon the weather. No activity can occur on the tundra until sufficient freezing permits movement of vehicles and the construction of snow roads and work pads. There is minimal weather data for the Mackenzie Delta and North Slope areas and a sharp dispute has risen as to the appropriate criteria for the starting date.

In the Tununuk Junction area, El Paso contends that construction cannot commence until 40 inches of ice cover the Mackenzie River. This is estimated to occur between November 4 and 28. For other northern areas El Paso uses the historical tundra opening date records; October 4 to December 21 for Mackenzie River tundra, and October 13 to November 22 for the Arctic Slope tundra. The median opening dates for the three areas, as estimated by El Paso, would be November 16, November 13, and November 2.

Arctic contends to the contrary that it can commence snow-road construction in mid-October. The historical tundra opening dates are dependent in part upon two factors that Arctic can influence -- when application is approved to enter the area and when sufficient snow has fallen or been manufactured to produce ground cover. 42/ Arctic asserts that snow-road construction can commence as soon as 300 freezing degree days have accumulated, which will result in freezing the active layer to a depth of 6 to 8 inches. At that point, Arctic plans to compact the snow with low ground pressure (LGP) vehicles which will accelerate ground freezing on the tundra. Heavy construction and pipelaying could begin when 700 freezing degree days have accumulated. The 20-year series of temperature data for Inuvik, which is in the same latitude as the North Slope of Alaska, suggests that 300 freezing degree days would be accumulated on a mean day of October 22; 43/ 700 degree day accumulation by a mean date of November 20. 44/ The El Paso method would defer initial entry until a mean date of November 16 in the Tununuk Junction area north of Inuvik. Judge Litt found the Arctic plan to be reasonable. We agree and thus find El Paso's representation of opening date for commencement of snow roads too pessimistic.

42/ El Paso argued that in some years entry to the tundra in Alaska was quite late. It may well be that the late entry was simply because no one applied to enter earlier.

43/ Assertion by Mr. Bergan, an attorney for El Paso. T. 233/40,584.

44/ Apparently, these data pertain to Norman Wells which is approximately 200 miles south of Inuvik. T. 233/40,611.

Secondly, El Paso surcharged each construction season with a 30-day lead time prior to commencement of pipelaying for the purpose of building snow roads and work pads. This, too, is in error for most of the spreads. Some lead time will be required, but no more than a few miles of right of way need precede the pipelaying. All preparations precedent to actually moving on to the right of way can be accomplished at the assembly points, during the summer. It is not credible that 30 days need elapse from the time snow pad construction commences until pipe is laid. Of course, where snow-road construction is necessary to enable the crews and equipment to move to the right of way, that factor must be added to the time requirements.

In summary, the El Paso risk analysis assumes later dates for initial entry onto the tundra, a mean of November 16, for the first year of Spread A, and charges 30 days for constructing snow roads prior to commencement of pipelaying. Thus, the mean date for commencement of pipelaying would be December 16. The effect is to deny to Arctic 25 to 30 days of prime late fall construction time. 45/ We find this projection to be an error which unduly biases the risk analysis against Arctic.

2. Productivity

The El Paso risk analysis of Arctic's proposal stated productivity in terms of calendar days. Initially, a rate of .35 to .45 miles per day was assumed. 46/ But in the final series of runs, El Paso purported to give "Arctic everything it proposed to do," 47/ and assumed .55 miles per calendar day. Apparently the .55 was increased for the more southerly areas and was roughly comparable to that proposed by Arctic. 48/

45/ The probability curve is shifted forward by that time.

46/ El Paso, Brief on Exceptions, p. 103.

47/ For Spreads A-F between Richard's Island and the 60th Parallel Arctic projects overall productivity of .65 miles per calendar day. T. 252/43,992.

48/ El Paso, Brief on Exceptions, p. 91.

But it seems clear that if that productivity was applied to a reasonable construction season, the results of the risk analysis would give Arctic high probability of meeting its schedule.

The other significant negative productivity factor in the El Paso risk analysis is the assumption that the main-line pipelaying productivity will drop to 50 percent of assumed normal productivity at any time a camp is being moved 49/ (several moves are provided during the construction seasons). El Paso argued that Arctic Gas did not plan for sufficient bed space in camp to accommodate the moving party. However, the solution according to Arctic Gas is to increase the camp facilities to the extent necessary to enable the pipeline crew to operate continuously rather than decreasing productivity. It appears that Arctic has made sufficient revisions in its camp facilities and cost estimates to minimize the impact on productivity of moving its crews. 50/ Arctic could provide sufficient camp facilities and avoid any moves during construction season for an additional $56 million. 51/

3. Other Variables

The other three factors in El Paso's risk analysis of the Arctic project have little significance. Snow road construction was assumed to vary only between .88 and 1.24 miles per day and initiation of pipelaying was seldom dependent upon prior construction of a snow road in the model.

49/ However, the final series of runs was made at 75% and 100% productivity during camp moves. See El Paso, Brief on Exceptions, pp. 100-104.

50/ T. 233/40,617-8.

51/ T. 233/40,533.

The rate of camp moving was significant only when productivity is assumed to decrease during the move. The rate of camp construction is relevant only in the few instances when the camp will not be built prior to the construction season. As to the latter, El Paso assumed a variance of only four days around the median time.

4. Summary

In the final analysis, we find that the El Paso risk analysis, although impressive in scope and detail, lacks sufficient realism to make the result a credible test of the Arctic Plan. By taking way the 25 to 30 days in the fall, almost all of which would be work days because of the relative mildness of the weather, the model starts Arctic off in each construction season at a critical disadvantage. Equally important, once the computer was set in motion it tracked through the entire construction program accumulating seasonal deficiencies and providing for no mitigative measures within or between seasons. Nevertheless, we do note that the El Paso criticisms produced a response by Arctic and that certain cost estimates were thereafter increased. In that sense, the El Paso analyses were of benefit to all.

In conclusion, we believe as did Judge Litt that Arctic has the ability to complete its construction program in the "manner and in the time frames proposed." 52/ There, of course, is some risk that construction could be slowed by adverse weather conditions, particularly in the final year on the North Slope and that construction would be delayed by up to one year. However, we believe that the risk is within an acceptable range and that it could be reduced substantially through expenditure of additional funds to provide additional production capacity as insurance. On the basis of our own analysis of cost of service, we find that even if an additional winter construction season is required and deliveries delayed for one year after expending the extra sums, the transportation cost per Mcf for Arctic would rise by only 12 percent.

52/ I.D. 164.

II. El Paso

A. Construction Plan and Costs

El Paso has scheduled a five-year period from approval and financing to first operation of the facilities. Pipeline construction for the base alignment will commence in the winter of the third year (now 1980) and conclude late in the fifth year (now 1982). The basic plan calls primarily for winter construction, although some summer construction is planned in the mountain areas (e.g., Atigun Pass and Chugach Forest) where wind and snow conditions would be too extreme for winter construction. Six spreads will be employed. Productivity estimates range from .67 miles per day for winter construction near and south of Fairbanks to .26 miles per day for summer construction in the Chugach Mountains. 53/

The El Paso winter construction plan was not seriously challenged on the record. It will use snow essentially only for work pads since the Alyeska haul road will be available near the right-of-way. The base case contemplates construction through the winter with a break at Christmas and an allowance of several off days for darkness and extreme cold. 54/

El Paso asserts that its cost estimates have been "fully verified within a small percentage." 55/ That statement can be accepted up to a point. But we do not believe that the El Paso construction program is so completely defined that there is no risk of increased cost estimates. The discrete units of the El Paso system will be discussed separately.

53/ El Paso, Application For Certificate, Volume III, §1.5, pp.6-7.

54/ El Paso, Brief on Exceptions p. 20 notes that for its realignment case no construction was planned from mid-December to early February. However, we do not recommend certification of the realignment case.

55/ El Paso Brief on Exceptions, p. 217.

1. <u>The Alaska Pipeline</u>

El Paso has accomplished minimal specific geotechnical and environmental analysis of the pipeline route. Detailed designs for crossing the active fault areas in Southern Alaska have not been prepared. The methods by which it intends to deal with the frost heave problem have been identified only generally. It intends to rely extensively upon Alyeska data, yet the degree of transferability of that data to the El Paso alignment has not been established. At points, the El Paso base alignment will be several miles from the Alyeska pipeline. El Paso certainly will be required to perform extensive independent core sampling and environmental analysis. Hydrostatic testing is proposed only at river and other pipeline crossings, but the feasibility of air testing near the Alyeska pipeline and the suitability of it for high-stress testing have been questioned by the Department of Transportation. 56/ El Paso intends to rely upon the Alyeska network for communications backup, but no agreement for such use was tendered and no apparent cost assigned thereto.

While El Paso has provided funds for most of the above items, it has provided only a five percent contingency account into which it must fit any cost increases. With the well-know hazards associated with construction in the Arctic, we do not believe that a five percent contingency will be adequate for the many demands which will be levied upon it. We believe that at least an additional five percent must be included to adequately respond to the risks.

Arctic witnesses initially estimated that the direct costs of El Paso construction would be 18 percent greater than the El Paso estimate. However, the basis of the Arctic estimate was a hypothetical system that in many respects was

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56/ Department of Transportation Comments on the Initial Decision, pp.3-4.

not comparable to the El Paso design. In the final analysis, the Arctic quantitative estimate suggests a possible direct cost increase for the pipeline in the range of five-to-ten percent due in part to optimistic initial costing and in part to abnormal weather and labor conditions.

2. The Alaska LNG Plant and Marine Terminal

Arctic witnesses estimated the cost of the Point Gravina liquefaction plant and marine terminal to be 5.2 percent higher than El Paso's estimate. Arctic argues further on exceptions 57/ that the inadequacy of El Paso's seismic design will cause additional cost increases. El Paso has made only a superficial on-site seismic analysis at Point Gravina. A geologist spent one day on the site making a visual examination. The seismic protective design of the plant is stated more in terms of objectives than precise delineation of the facilities.

Arctic emphasizes the testimony of its seismic witness, Dr. Newmark, that:

> "I have no basis for estimating the adequacy or conservatism of their allowance for additional costs to take account of seismicity and other factors involved, because their design spectra and allowable stress levels have not been described sufficiently to permit judgment to be applied." 58/

57/ Arctic Brief on Exceptions pp. 8-15.

58/ T. 157/25,927, 25,954-25,970.

The El Paso witness conceded that much site survey and detailed design work remains to be done prior to the commencement of construction, but insisted that there had been prepared a "sufficient design to have a high level of confidence in the sizes of structures, which is what affects the costs." 59/ The general design and estimates were based upon an earthquake 8.5 Richter scale magnitude and 0.6 g. ground acceleration. It was stated that there was adequate reserve built into the estimates to enable construction of the finally determined seismic protective features. 60/

We agree that the El Paso seismic studies and designs are in the embryonic stage. But, the El Paso consultants are not novices in design and construction of complex facilities in seismic sensitive areas. We believe that adequate time has been provided in the schedule to complete studies and designs after a final decision in this matter and that the cost estimates are valid if allowance is made for some increases. Accordingly, we reject the Arctic suggestion that the El Paso seismic design lacks sufficient specificity to permit certification of the El Paso system.

Finally, El Paso has not established the environmental acceptability of the thermal discharge from its liquefaction plant. The discharge will be twenty degrees higher than the ambient water temperature in Prince William Sound. Cooling towers or some form of staged heat reduction process may be required, which would add a substantial although unspecified cost to that facility. Federal and Alaskan authorities must make additional decisions concerning the discharge.

59/ T. 170/27,959.

60/ T. 170/27,954-70.

3. LNG Tanker Fleet

El Paso estimates the cost for an eight-ship LNG tanker fleet to be $1,614,194,000. Witnesses for Arctic estimated the cost at $1,756,691,000 or 8.8 percent higher. Arctic urged that the testimony of its witnesses be accepted since they were "objective and unbiased." 61/ El Paso in effect agreed. 62/ These additional costs are not taken into acount in the cost figures reported at the beginning of this chapter, but will account for part of the cost overrun we anticipate.

4. Lower 48 States Facilities

There was no significant disagreement between the witnesses concerning the El Paso facilities in the lower 48 states. Arctic estimated the Western LNG regasification and pipeline facilities in California would cost one percent more than did El Paso.

The facilities east of California involve garden variety pipeline construction and equipment in often traversed pipeline country.

In fact, the cost of the new 42-inch pipeline from Waha to Refugio, Texas, may be overstated in relation to the ultimate need. That facility is provided under El Paso's low case to transport approximately 800,000 Mcf per day to pipelines that serve the Eastern United States.

However, there currently exists excess capacity on intrastate pipelines that traverse that same route. Pursuant to the Emergency Natural Gas Act of 1977, new interchange facilities were installed between interstate and intrastate pipelines in that area and a capacity for the transfer of 500,000 to 600,000 Mcf per day from the Permian Basin to the

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61/ Arctic Reply Brief, Economic Considerations, p. 40.

62/ El Paso Rebuttal Brief, Cost, Scheduling and Economics, pp. 21-22.

Texas Gulf Coast was made available. Under normal circumstances, that capacity is not available for natural gas moving in interstate commerce because such transportion would subject the intrastate pipeline to the jurisdiction of the Federal Power Commission.

If the El Paso project is selected, consideration should be given to legislation that would permit the utilization of the intrastate pipelines for the transmission of Alaskan natural gas. El Paso estimates the cost of the Waha-Refugio line at $223,000,000. Although it is not possible to predict at this time the amount of intrastate capacity that will be available in 1982, it is probable that the capital expenditures for new pipeline could be substantially reduced through the use of existing intrastate facilities. The potential savings here were not reflected in the cost estimates made at the outset of this chapter and would tend to offset other items that are liable to cost over-run.

5. Summary

We believe that the El Paso cost estimates are reasonably reliable. Nevertheless, the adjustments that were suggested in the hearing, the extensive research and design that must be accomplished prior to construction of the pipeline and Alaska LNG facilities and the rugged terrain through which the pipeline must pass lead us to assign to El Paso a high probability of cost increases in the range of 7 to 10 percent for the facilities to California. Additionally, if Oxnard is the site for the California regasification facility, El Paso will incur additional expenses and increase the capacity of the LNG fleet, but that increase will be substantially offset by the savings at the Oxnard site.

B. Construction Schedule

El Paso plans to be in partial operation during the sixth year (now 1983). 63/ Arctic challenges the El Paso construction schedule, principally upon the bases that much preconstruction seismic research and design must be accomplished and the large expansion of existing operating systems involved in the LNG liquefaction plant and LNG fleet will cause delay. Taking account of all that El Paso must do, Judge Litt nevertheless found that the El Paso system "can be built in the manner and in the time frames proposed." 64/ We find no basis for reversing that finding. El Paso has allowed about two years of preparation prior to actual commencement of construction on the Alaska LNG facilities and nearly three years for the pipeline. The tasks yet to be performed -- detailed survey and design -- can be accelerated to the extent necessary through infusion of money, of which we do take account.

The necessity to build LNG plants and ships on a larger scale than heretofore presents some risk that unexpected problems could delay El Paso's project. That risk is not large, however, and we concur in Judge Litt's finding that El Paso's construction schedule is basically credible.

63/ On the final day of the hearing, the testimony of a Staff witness implied that El Paso planned to make no deliveries until the seventh year. T. 253/44,340-1. Apparently, the witness was mislead by the fact that El Paso Statement of Income and Retained Earnings for the sixth year shows no operating expenses. T. 253/44,357-8. Instead, El Paso subtracts the operating expenses for that sixth year from the revenues derived from the partial operation and the net is capitalized. There is no doubt that El Paso plans to make partial deliveries of gas during that sixth year.

64/ I.D. 164

In conclusion, we find that El Paso has satisfactorily established that all of the facilities for its project can be constructed within the time proposed.

C. Ship Requirements

1. Capacity

El Paso proposes for its 2.3614 Bcfd case, eight LNG tankers with 165,000 cubic meter nominal capacity and 6 LNG liquefaction trains. 65/ Judge Litt concluded that these facilities were not adequate to produce and transport the projected volume of gas reliability and added the $400 million cost of one ship and one LNG train. El Paso contends that the conclusion is "wrong." 66/

The 165,000 cubic meter design capacity of the tankers must be reduced by two factors. First, the Coast Guard permits LNG tankers to be loaded only to 98 percent of capacity. Second, during the ballast trip back to Alaska some LNG (called "heel") must be retained to keep the tanks cool and to enable prompt loading in Alaska. The "heel" remaining when the ship reaches Point Gravina is approximately 353 cubic meters. The capacity of the ship thus is reduced by that amount. The net capacity of the ship is (165,000 X 198) - 353 = 161,347 cubic meters. The production of the Alaska LNG plant will be 37,422,000 cubic meters annually. Therefore, 232 (231.9) round trips per year are required to ship the production of the plant to California.

65/ The ratio used by El Paso of a cubic meter of natural gas to a cubic meter of LNG is 593:1. The ratio varies with the amount of the heavier hydrocarbons such as ethane or propane, i.e., the Btu content of the gas. The ratio for pure methane is 625:1. (I.D. 147-48.) There are 35.314 cubic feet per cubic meter. Thus,

$$\frac{\text{LNG}(M^3 \times 593 \times 35.314}{1000} = \text{Mcf of natural gas.}$$

66/ El Paso Brief on Exceptions, p. 235.

Judge Litt determined that the eight-ship fleet could make only 211 round trips per year. El Paso contends that there are several errors in the computation. The most significant issue relates to the random delay and repair allowance.

The base point from which to determine generally whether the capacity is adequate is the average roundtrip time for the vessels and the number of operational days per year. El Paso assumes that each ship will be out of service 20 days per year for drydocking. This leaves 345 base operating days. In addition, ships will be out of service at random times for repair or will encounter unanticipated delay. El Paso estimated 15 days per year for random repair and delay, leaving 330 days for full service. The 330 days were adopted by Judge Litt as the operating year.

The next step is to calculate the average round trip time. At one point early in the hearing, El Paso estimated the round trip time between Point Conception and Point Gravina at roughly 11.5 days, which Judge Litt used in the initial decision. 67/ However, El Paso subsequently refined the data as follows:

1.	loaded voyage	4.42 days
2.	unloaded voyage	4.32 days
3.	LNG Point Gravina	1.32 days
4.	Regas. Point Conception	1.25 days
5.	Total	11.31 days

The 11.31 day average round trip and a 330-day operating year yield 29.1 voyages per year for each ship or an adequate total of 233.4 trips per year for the fleet. El Paso further notes that 15 days of random repair and delay can be added to the average trip as .53 days. This factor would increase

67/ I.D. 139-40.

the average trip to 11.84 days. El Paso contends that 11.31 is proper for a 330 day year and 11.84 for a 345 day year:

$$\frac{330}{11.31} = 29.1 \text{ X } 8 \text{ ships} = 233.4 \text{ trips}$$

$$\frac{345}{11.84} = 29.1 \text{ X } 8 \text{ ships} = 233.1 \text{ trips}$$

We agree with El Paso on this point.

If El Paso's assumptions otherwise are correct, the eight ship fleet is sufficient for Point Gravina to Point Conception. However, the fleet is not adequate to deliver the LNG to Oxnard, which is 70 miles south of Point Conception. At 17.9 knots loaded 68/ and 18.3 knots in ballast, the additional mileage requires 3.91 and 3.83 hours each way for a total of 7.74 hours of .32 days. The round trip becomes 12.16 days. Thus, using Oxnard, the number of trips per year is 226.9 -- not a sufficient number.

El Paso further disagrees with Judge Litt on several subsidiary points which we shall address.

2. Weather in Port

Judge Litt found that insufficient time was allowed for weather-induced port closure at Gravina and Conception. It was assumed that the Point Gravina would be closed 25 percent of the time from October to April because of wave heights over 4 feet. 69/ Apparently, the 25 percent was derived from Ex. EP-98, Table 2A.5-2. El Paso now argues that the table specifies only the average number of events from October to April, *i.e.*, 25.8 is the number of times the port would be closed for up to 6 hours. This is contrary

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68/ We also accept El Paso's statement regarding transit speed in the Santa Barbara Channel. El Paso Brief on Exceptions, p. 240-1.

69/ I.D. 144.

to the textual explanation in Ex. EP-98. But it appears that the textual statement is incorrect. Table 2A.5-3 clearly states the probability of 6 hours duration of 4-foot waves to be 6.9 percent, not 25.8 percent.

El Paso assumed an overall probability of port closure from all causes, waves, fog, etc., to be 20 percent in December and January and two percent in July and August -- the mean for the year being 11 percent. 70/ These data appear accurate and El Paso assumptions regarding port closure are reasonable.

3. Dry Dock and Cool Down

El Paso assumes that each ship will be out of service 20 days for dry-docking, including two days travel to dry dock, 14 days in dry dock, and four days for travel out and cooling down before the ship returns to service. Assuming the dry dock to be in San Diego, Judge Litt reasoned that a trip of 2,107 miles to Gravina would take 4.7 days and since no LNG injection facilities were located on the West Coast, the ship would have to be cooled down for two additional days at Gravina. It was concluded that two additional days should be allowed the dry dock cycle each year, reducing the service days to 328. 71/

El Paso asserts that more than ample time is allowed. It appears that El Paso is correct. The dry dock cycle is simply an extension of one round trip each year. When the ship leaves dry dock, it will be back into the round trip cycle when, after 11 or 12 hours of steaming, it reach Point Conception (or Oxnard). The Conception to Gravina leg is already accounted for in the round-trip analysis and therefore should not be charged to the dry dock time. When the ship

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70/ See T. 52/7781.

71/ Judge Litt also mentioned the need to warm and evacuate the tanks in dry dock possibly requiring more time than allowed and the possible shortage of dry dock facilities on the West Coast.

reaches Gravina, it will be idle for two days for cool-down, but the total time chargeable to the dry-dock phase in that instance will be 2.5 days, leaving 1.5 days as a reserve. Therefore, the 20-day allowance for annual dry docking is adequate.

4. Service Speed

Judge Litt questioned the service speeds assumed by El Paso principally on the basis that occasional heavy weather could slow the ship to avoid "slamming" 72/ or time-consuming course changes. The Judge used this argument as added justification for requiring an additional ship. El Paso asserts that it will not encounter "slamming" -- none has been encountered in several years of operation of the the Phillips-Marathon ships that run between Cook Inlet in Alaska and Japan 73/ -- and the impact of heavy sea is accounted for in the El Paso's model. 74/

El Paso has not made available to the Commission its computer programs for the model, 75/ and, therefore, we have no method for ascertaining the manner in which weather and sea conditions are reflected. Thus, we perforce accept for the present El Paso's statements that the 18.5 knot service speed when reduced to an average 17.9 knots loaded and 18.3 knots in ballast accounts for the impact of all weather and sea conditions.

72/ Disruptive movement of the LNG cargo.

73/ El Paso Brief on Exceptions, p. 242.

74/ T. 51/7,718.

75/ El Paso, Brief on Exceptions, pp. 467-8 defends the refusal to make available the Fleet simulation program on grounds that the information is proprietary and that the data is not necessary to a decision.

5. Night Operation

Judge Litt raised a question as to restrictions on night operations in port. El Paso states that no restrictions on night operations are contemplated at Point Gravina or Conception. Apparently, no restrictions now exist at Oxnard, but staff contends that there would be a "reasonable possibility that night operations might be restricted." 76/ A mere possibility of restricted night operations is not a basis for requiring construction of an entire tanker at this time.

6. Summary

FPC Staff continues to question the overall reliability of the eight-ship fleet for the Gravina-Conception service on the basis that "it would be improbable that delays due to weather and sea conditions, port closures, random repairs and delays would occur on an average basis." 77/ Staff is particularly concerned with the winter season when weather conditions would be worst and the need for gas greatest. While it is clear that El Paso has sixed and scheduled its ships to a close tolerance, we do not believe that the average conditions or average times are pertinent. A properly constructed stochastic model could correctly predict the the operation of the overall fleet by using probabilities of occurrence of successive events rather than averages. It appears that El Paso's model is the latter type, 78/ and that the averages stated by El Paso are observations of the results of the model rather than inputs. Again, not having access to the program we do not know this for certain.

Bad weather and sea delays will be concentrated in the winter months. However, El Paso has control over the single largest delay factor -- dry docking. It can be scheduled

76/ Staff Report, April 8, 1977, p. 65.

77/ Staff Report, April 8, 1977, p. 63.

78/ El Paso Response to Staff, April 27, 1977.

in the periods when other types of delay are least probable. All ships would be in service in the winter. We believe that El Paso has provided adequate reserve for reliability, but barely, and their system is subject to the risks of extraordinary events discussed in Chapter VII.

Of course, accepting the El Paso argument, the eight 165,000 cubic meter ships would be inadequate for service to Oxnard. Either the eight ships must be increased in capacity or a ninth ship would be required. El Paso has stated that it would redesign the system and could expand its tanker capacity to 175,000 cubic meters although the largest ship in existence today has a capacity of only 125,000 cubic meters. 79/ Since the same block coefficient (basic design) could be maintained and, at this point, 175,000 cubic meter ships are no more hypothetical than 165,000 cubic meter ships, the expansion may be feasible.

El Paso has stated that the capital cost of increasing capacity or adding another ship would be about the same. 80/ It also notes that locating the regasification facility at Oxnard would result in substantial savings in utility connections and pipeline to transport the gas east of California.

D. Train and Tank Requirements

Judge Litt found that El Paso would need an additional LNG liquefaction unit ("train") at Point Gravina to liquefy all of the gas projected to flow from Prudhoe Bay. Upon reexamination, we find that six trains will be adequate and provide sufficient reliability.

For each train, there is an allowance of 20 days per year per train downtime; fifteen days per year scheduled maintenance and five days per year unscheduled maintenance. 81/

79/ I.D. 156.

80/ El Paso Brief on Exceptions, p. 252.

81/ Ex. EP-65, p. 3.1.54.

In addition, there is a built-in excess capacity for each train of five percent above its average production. 82/

It is analytically convenient to divide the year into three periods as did Judge Litt. Period A of 120 days in which there are seven tankers and five trains; Period B of 40 days in which there are seven tankers and six trains, and; Period C of 205 days in which there are eight tankers and six trains. Utilizing the 2,272 MMcf per day LNG production volume per train, the 11.84 days round trip per ship, and a tanker capacity of 3378.5 MMcf, we obtain the following:

Time Period	Duration (Days)	Train Output (MMcf)	Tanker Capacity (MMcf)
Period A	120	227,134	239,690
Period B	40	90,863	79,896
Period C	205	465,760	467,967

Thus, the six trains can produce 783,757 MMcf per year which is larger than the required 783,665 MMcf per year. Only in Period B is the train capacity nominally below the tanker capacity, by less than five percent. During that period, the five percent excess capacity of the trains could be used to alleviate the deficiency.

Finally, Judge Litt found that El Paso would require an additional LNG storage tank at Point Gravina. El Paso concedes that there may be a "marginal" need for such facility 83/, but takes issue with the basis of the conclusion. It appears that the conclusion is founded in part upon a misinterpretation of Ex. EP-98, 2A.5-7. However, in view of the current uncertainty concerning the sizing and number of ships that would serve Oxnard, no decision on the storage tank can be made at this time.

82/ T. 52/7764.

83/ El Paso Brief on Exceptions, p. 255.

III. Alcan

A. Construction Plan and Costs

Alcan proposes to commence mainline construction in April of 1980 and complete it by October of 1981. Additional compressor station construction will continue into 1982 to bring the system to design capacity of 2.4 Bcfd by January 1, 1983. A maximum of 15 spreads is planned for Alaska and Canada, six in Alaska, nine in Canada the first summer and eight the second summer. In Alaska, winter construction is planned only for stream crossings. There will be two spreads operating in the winter in Canada through areas of muskeg.

The estimated costs for the Alcan 48" alternative obviously have not been subjected to detailed scrutiny by the opposition and to review thereafter. Up to a point 84/ Alcan costs can be verified indirectly by reference to the El Paso cost estimates. While that common base works only as far as Delta Junction, the overall costs stated by Alcan for the Alaska portion of the line are not unreasonable. Even Arctic concludes that the Alcan costs in Alaska should be increased by only seven percent. Nevertheless within Alaska there are unresolved issues that may lead to cost increases of the Alcan system.

84/ Not completely; from information currently available the material cost for the Alcan 48" system is $901,000 per mile compared to El Paso's $994,000 per mile for 42" pipe notwithstanding that Alcan requires 22% more steel. Staff Report, April 8, 1977, p. 24.

1. Alignment with Alyeska

Between Prudhoe Bay and Delta Junction in Alaska, Alcan retains for the 48" alternative the same alignment proposed for the 42" proposal. This alignment closely follows the Alyeska oil pipeline for the purpose of making extensive use of the Alyeska work pad, reducing gravel requirements and minimizing environmental impact.

Staff continues to argue that the environmental advantages of that alignment are "largely negated by the safety hazards" 85/ that arise from the necessity of blasting near the Alyeska line and the threat of vehicle collision with the vertical support members (VSM) where the Alyeska pipeline is above ground. Alcan has filed some preliminary studies regarding the use of controlled explosive to minimize the threat from blasting. 86/ Alcan also downplays the risk of injury to the VSM's. We believe that it will be possible to develop and follow a construction plan that presents acceptable minimal risk to the Alyeska pipeline. Whether, in the final analysis, that alignment will be superior in terms of costs and environmental impact to an alignment such as the El Paso base case 87/ cannot be ascertained at this time.

85/ Id., p.34

86/ See Alcan Interrogatory Ex. #19; Alcan answer to Staff Interrogation #19 of March 22, 1977.

87/ The El Paso base alignment averages about 3,000 feet separation from Alyeska, but in places the separation is a few miles. El Paso estimated that costs for its realignment adjacent to Alyeska would increase by $37 million.

Recent communications between Alyeska and Northwest Pipeline Company suggest that further substantial modification of the Alcan alignment may be required. The original Alcan alignment assumed a separation between the oil pipeline and the natural gas pipeline of 70 to 80 feet. 88/ A letter of December 15, 1976, from Alyeska to Northwest established preliminary general guidelines for separation of the natural gas pipeline where blasting is required of 200 feet from the buried sections of the oil pipeline and 100 feet from the elevated sections of the oil pipeline. 89/ Approximately 350 miles of the 500 miles between Prudhoe Bay and Delta Junction will require some blasting 90/ and it would appear that virtually an entire new work pad would be required in those areas. Gravel requirements and costs would increase, the Alyeska data would become less relevant, and much of the environmental benefit of the Alyeska alignment would be lost.

Furthermore, there is a gravel shortage north of the Brooks range 91/ which could require long distance hauling of gravel or require winter construction using snow work pads. Thus, questions remain as to the cost of the Alcan system with an alignment near the Alyeska pipeline.

88/ Alcan Application for Certificate, Ex. 2Z-1,p.26, June, 1976.

89/ Alcan Answer to Arctic Interrogatory #43 of March 22, 1977. The letter cautions that in "certain areas final separation distances may exceed the above general guidelines."

90/ Alcan Answer to El Paso Interrogatory #89 of March 22,1977.

91/ I. D. 113.

2. Cost and Productivity

Alcan has submitted cost estimates for construction in Canada that are significantly lower than the costs submitted for Alaska and lower than the cost estimates of Arctic for construction in similar rights-of-way. Arctic and El Paso sharply question the accuracy of those estimates. Arctic notes that the capital cost per mile for Alcan construction in Canada is estimated at $1,300 compared to $3,340 in Alaska. Arctic contends that there are inexplicable differences in the estimated cost of pipe installation. On a per foot basis, Alcan's estimates are $167 in Alaska; $108.28 in Canada for the Westcoast; $82.31 in Foothills; and $33.13 for Alberta Gas Trunkline.

Alcan responds that terrain, labor costs, and construction practices explain the disparities. Alcan states that the $82.31 cost for Foothills should be increased by transportation costs to $101.31 to make it comparable to the Westcoast estimate of $108.28. In comparing Alaska to the Yukon or British Columbia, Alcan estimates that the labor cost in Alaska is twice as great and productivity is 23.5 percent less. The compounded effect, it alleges, makes the estimates comparable. 92/

With respect to the large differences in estimated costs between Alberta and other parts of Canada, Alcan offers statements of historical costs incurred by AGTL. It also states that the estimates were developed with the assistance of a major (unnamed) Canadian pipeline contractor. While the explanations submitted by Alcan for the differences in cost between Canada and Alaska are somewhat helpful, there is no adequate basis upon which to evaluate the reliability of costs for all portions of Canada.

92/ Alcan Response, April 8, 1977, App. D, p.7.

El Paso challenges the productivity rates submitted by Alcan. Alcan projects a productivity in Alaska of .71 miles and 50 joints of welding per working day or .43 miles per calendar day. This is essentially the same rate as Arctic projects for winter construction on the North Slope and well within theoretical limits. However, Alcan's Canadian partners project productivity and welding rates for 48-inch pipe that are very high relative to those projected by any other applicant. Foothills projects 85 joints and 1.046 miles per working day for summer construction, and 64 joints and .788 miles per working day for winter construction. Westcoast estimates 90 joints and .903 miles per working day and AGTL peaks at 115 joints and 1.416 miles per working day for summer construction. 93/

By contrast, Arctic Gas utilizes a rate or productivity for winter construction of 48-inch line in Alberta of .84 miles per working day, which with nominal 80-foot sections would be only 55-59 joints per working day. 94/ The AGTL productivity estimate is 40 percent higher, 1.17 miles and 95 joints per working day for winter construction. 95/ Perhaps there is an explanation for the vastly higher and constantly increasing productivity for the Alcan members in Canada, but none is apparent from the material provided.

93/ Alcan Answer to El Paso Interrogatory #97 of March 22, 1977.

94/ T. 202/34,467.

95/ Alcan Answer to El Paso Interrogatory #97 of March 22, 1977.

3. Summary

In summary, we do not believe that the cost estimates for the Alcan 48" system can be accepted as final. To date, there has been only a minimal opportunity for the FPC staff or other applicants to examine the estimates. There has been only minimal opportunity for Alcan to answer questions properly raised.

We note that particularly the costs in Canada will be subjected to cross-examination and consideration before the National Energy Board. We believe that a continuing evaluation of the Alcan costs should be made through review of the NEB proceedings.

Nevertheless, we believe that the Arctic system can be constructed with an acceptable risk of cost increase. Because of the recent information regarding the alignment with the Alyeska oil pipeline, it is necessary to assign a high probability of cost increases which would be as high as 5 percent of the estimates for the Alaska portion.

The costs in Canada are subject to uncertainty. A comparison of those cost estimates with Arctic's cost estimates for similar terrain in Canada and with Alcan's Alaska cost estimates causes us to assign to Alcan a high probability of cost increases in Canada of at least 10 percent to account for possible underestimation.

B. Construction Schedule

With projects of this magnitude much preliminary work must be completed before actual construction can commence. Most of these tasks are costly and have little or no market value by themselves. No applicant is eager to spend money on such items before being selected. Among these items are:

1. Final detailed environmental and seismic studies,

2. Final alignment of the pipeline and siting of other facilities and final design,

3. Acquisition of right-of-way, including title searches,

4. Raising several billions of dollars of private financing,

5. Final specification and approval of pipe and commencement of pipe manufacture,

6. Completion of bidding and contracting,

7. Route survey,

8. Assembly of equipment and personnel, and

9. Civil construction of staging sites, work yards, roads, etc.

El Paso and staff contend that Alcan has provided too little time for this preconstruction phase. Comparison of the applicant's construction schedules measuring back from currently proposed dates of initial operation indicates that the disparity overall between applicants is not great. Foothills proposes to commence with two spreads in the summer of 1979. This seems doubtful. Alcan proposes to commence pipeline construction in Alaska in April of 1980. El Paso plans to commence in August 1980 and Arctic in October or November 1980. Although Alcan may be farther behind than the other applicants in many areas of study and preparation, it presumably will be able to rely upon Alyeska data to the greatest extent. There is no reason to expect that Alcan could not commence pipeline construction in the same year as the other applicants. Nevertheless, we believe that no decision should be predicated upon Alcan commencing pipeline construction prior to mid-1980.

Alcan proposes to construct 2,754 miles of pipeline in Alaska and Canada in a two-year period during which 2,028 miles contemporaneously are being constructed in the lower 48 states on the eastern and western "legs."

El Paso estimates that in the summer of 1980, the Alcan project will require 23 mainline spreads, 14 compressor station crews, and 16,300 employees; in 1981, 24 mainline spreads, 18 compressor station crews and 17,358 employees. 96/ These are far greater manpower requirements than currently available. AGTL estimates a demand in Canada for all Canadian spreads of 3,950 supervisors, welders, and other skilled trades. The currently available workforce is only 2,405. 97/

These high labor demands inevitably will lead to employment of less fully trained and experienced personnel, which will cast doubt upon the already generous productivity estimates for construction in Canada. In conclusion, while we believe it to be probable that the Alcan pipeline could become operational in mid-1982, up to one year earlier than Arctic or El Paso, we cannot, on the basis of evidence available to us, accept Alcan's estimate of October 1, 1981.

96/ El Paso Response, April 8, 1977, p. 18.

97/ Alcan filing, March 22, 1977, AGTL Vol. 1, p.3, D. 5-1.

C. Summer Construction - Environmental Acceptability

Alcan proposes to construct the Alaska section in two seasons, mid-April to the first of October in the first year, and the first of April to the first of August in the second year. Some river crossings would be constructed during the winter. Referring to the staff sponsored geotechnic evaluation of the Alcan proposal,98/ Judge Litt found that "summer construction in Alaska cannot be accomplished without unacceptable environmental impact." 99/ We believe that to be too sweeping a generalization. The principal reason given for it was that "degradation of ice-rich permafrost results from summer construction." However, not all of Alaska is covered by ice-rich permafrost and the term "summer construction" can include the fall and spring months when the ambient temperature is below freezing.

The witnesses that sponsored the summer construction critique in ST-51 testified that, with the exception of approximately 40 miles, 100/ the portion of the Alcan route from Delta Junction to the Yukon border has "generally quite good" foundation materials 101/ and that summer construction will be appropriate. 102/

98/ Ex. ST-51, pp. 177-185.

99/ I.D. 161.

100/ The problem areas could be reduced to a few miles by realignment nearer the foothills in wet areas.

101/ T.234/40,781.

102/ T.234/40,780.

Between Prudhoe Bay and Delta Junction, the areas with the greatest threat, degradation would occur where the Alyeska pipeline is elevated, which covers approximately one-half of the distance. Since that line will be heated, it was buried only where it can rest upon soils that are thaw stable or not permafrost, e.g., bedrock or soil devoid of permafrost, or frozen, thaw stable sand and gravel. 103/ In those areas, Alcan could construct in summer without serious environmental risk, but these conditions are not entirely a blessing. Such areas typically require substantial blasting and some fine grained thaw stable soils are more susceptible to frost heave. 104/ Also, there is no assurance that the soil characteristics will always be similar 200 feet from the oil pipeline.

The most sensitive areas would be slopes with ice-rich, fine-textured soils with relatively high permafrost temperatures. 105/ But this situation exists over only two to five percent of the route, 106/ and construction at these points could be scheduled for times when the ambient temperature is below freezing. 107/

103/ See Ex. EP-252, pp. 4-6.

104/ Id. p. 20.

105/ ST-51, p. 178.

106/ T. 234/40,854

107/ T. 234/40,858.

To the extent that some construction must occur during summer in ice-rich areas, there are measures that can mitigate the thawing of the permafrost while the ditch is open. Straw or styrofoam can be used to insulate the open cuts. Alcan argues that by allowing the ditch wall to thaw back, the vegetative mat then slopes into the ditch and operates as self-insulation. However, this method would seem more appropriate for the context in which it appears in the record, namely, when a permanent cut is made on the side of or through a hill. There, the original cut could be sized to take account of the subsidence. As for a pipeline trench that is going to be filled, the subsidence results only in wider ditch and berm. It would be preferable to trench such areas in freezing weather.

In conclusion, we cannot find the Alcan summer construction plan to be unacceptable in its entirety. 108/ Much of the construction could occur in the summer without any more adverse environmental impact from permafrost degradation than would result from winter construction. There are areas in which early spring or late fall construction must be mandated. There are substantial areas in which the impact upon the environment would be less from construction when the ambient temperature is below freezing. In those areas, Alcan must give further consideration to its summer construction program and justify it on a site specific basis to the person monitoring construction. In general, however we find that the Alcan summer construction program can be conducted in a manner that will be environmentally acceptable.

108/ We note that the Alyeska pipeline was constructed primarily in the summer. This does not imply that we have a basis for independent judgment as to the environment acceptability of the Alyeska pipeline.

CHAPTER IX

THE WESTERN LEG

A. Introduction

Section 5(b)(1) of the Alaska Natural Gas Transportation Act states that:

> "Any recommendation that the President approve a particular transportation system shall . . . include provision for new facilities to the extent necessary to assure direct pipeline delivery of Alaska natural gas contemporaneously to points both east and west of the Rocky Mountains in the lower continental United States." (Emphasis added.)

The "western leg" issue in this proceeding deals with the manner by which the western states would have access to Alaskan gas in the event that the gas is brought to the lower 48 states by an overland transportation system through Alaska and Canada. Specifically, the issue is to what extent new pipeline facilities should be constructed to provide direct access to the Alaskan gas for the western states or whether this gas can be transported solely through the existing lines without expansion. Both Arctic Gas and Alcan propose to construct a virtually identical "eastern leg," which would transport gas from Alberta to eastern markets. No opposition to the eastern leg has yet materialized. 1/ The western legs

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1/ Arctic Gas had originally proposed that its eastern-leg facilities extend to Delmont, Pennsylvania, thus affording direct delivery to each of the six Northern Border Pipeline companies. Acceding to a Commission Staff recommendation, it now proposes to terminate Northern Border's facilities near Dwight, Illinois; make direct deliveries to Northern Natural Gas Company, Michigan-Wisconsin Pipe Line Company, and Natural Gas Pipeline Company of America; and make deliveries by displacement to Panhandle Eastern Pipe Line Company, Texas Eastern Transmission Corp. (I.D. 271.)

as proposed by Arctic Gas and Alcan are also very similar and are shown diagrammatically in Exhibits IX-1, IX-2, and IX-3.

Direct delivery of Alaskan gas to the western states could be provided by utilizing the existing pipeline systems which import gas from Canada. Any additional capacity needed to transport the Alaskan gas could be provided by looping those existing pipelines. 2/ However, the amount of looping that will be required is dependent upon two currently unknown variables, the quantity of future Canadian imports and the quantity of Alaskan gas that is contracted for sale in the western states.

If full looping is required, the total new construction on the western leg would be:

		Proposed System	
Location	Miles	Arctic Gas	Alcan
1. Alberta (Caroline Junction to Coleman)	176	Canadian Arctic Pipeline Company	Alberta Gas Trunkline Ltd.
2. British Columbia (Coleman to Kingsgate)	105	Alberta Natural Gas Co. Ltd.	Westcoast Transmission Co. Ltd.
3. Idaho, Washington, Oregon	592 3/	Pacific Gas Transmission	Pacific Gas Transmission
4. California (to Antioch)	282 3/	Pacific Gas and Electric	Pacific Gas and Electric

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2/ Looping is constructing a new pipeline parallel to and connected with an existing pipeline.

3/ Represents amount of looping required on existing pipeline to transport additional 600 MMcf/d.

Direct access could be supplemented by a displacement plan utilizing the Permian Basin area as the origin of the western states' entitlements of Alaskan gas. 4/ Displacement could be either an interim measure or a long-term supplement to direct access. The extent of displacement potential likewise depends upon future gas supply development from the traditional producing areas that serve the West.

Definitive statements cannot now be made on all of the considerations that must be weighed to determine the most efficient, flexible and economical way of transporting Alaskan gas to the western states. Therefore, the Commission recommends that any decision as to the need for additional new facilities to meet the mandate for deliveryying Alaskan gas to the western states be deferred from one to two years when more information will be available.

B. Description of Facilities

While the Commission recommends deferring the actual decision on the need for new facilities to supply gas to the West, we report here the facilities for that purpose which have been proposed. Each version is predicated upon the volume of gas assumed to be available to the western states and the method for transporting the gas. The western leg, as proposed by Arctic Gas and Alcan in its "48-inch Alternative" system, would generally parallel existing gas transportation facilities extending from south-central Alberta to San Francisco. The existing facilities are 1,204 miles of a 36-inch diameter transmission line operated at a maximum pressure of 911 PSIG which span two provinces of Canada and four western states. The pipeline was constructed in the in the period 1959-60 and placed in operation in 1961. At present this 36-inch line has just over 100 miles of 42-inch and 36-inch diameter looping, portions of which were installed as recently as 1970. The new western leg would be a further duplication of the existing line in the existing right-of-way and the two would be operated as one facility.

4/ In addition to the Permian Basin area, gas supplies from the San Juan Basin area and the Panhandle-Hugoton area possibly could be used in a displacement scheme.

Several versions of the new western leg have been considered and are described as follows:

To move minimum volumes of gas, Pacific Gas Transmission Company and Pacific Gas & Electric Company (PGT/PG&E) had proposed an "1180 Design" which would require the construction of 485.4 miles of 36-inch diameter pipeline loop at 17 locations along their existing 917-mile long pipeline extending from the U.S.-Canadian border to Antioch, California. No compressor station horsepower additions would be required for this proposal. This system would transport 200,000 Mcfd of gas. [See Exhibit IX-2.]

PGT-PG&E have also proposed three alternative pipeline designs which could be constructed to carry larger volumes of gas. Their "1830 Design" would require the construction of 917 miles of 36-inch diameter pipeline parallel to the existing system. This design would require the addition of four compressor stations and would have a capacity of 850,000 Mcfd.

The second alternative proposed for transporting large volumes of gas would require 917 miles of 42-inch diameter pipeline installed parallel to the existing pipeline. This system would also require four compressor stations and would have a flow capacity of 1.2 Bcfd.

Their third and now preferred alternative, the "1580 Design," would require construction of 873.5 miles of 36-inch diameter pipeline thus completing the looping of the 917-mile system. No additional compression would be installed. This system would transport 659,000 Mcfd of gas. [See Exhibit IX-3.]

The preceding description of facilities was taken from the Judge's Decision (Appendix A, page 3). The Staff Brief on Exceptions states that a total of ten versions of the western leg have been suggested (Page 6, footnote 1).

Western Leg Description 1/

A 30–inch O.D. high pressure pipline from Caroline, Alberta to the Alberta/British Columbia border. These facilities would be constructed and operated by Canadian Arctic Piepline Company, LTD. (CAGPL). 2/

A 36–inch O.D. pipeline from the Alberta/British Columbia Border to Kingsgate on the international border between British Columbia and Idaho. These facilities would be constructed and operated by Alberta Natural Gas Company, Ltd. (ANG), and they would parallel ANG's existing pipeline facilities. 3/

A 36–inch, 911 psig pipeline, without any new compression, from Kingsgate to Malin, Oregon on the Oregon/California border. These facilities would be constructed and operated by PGT and would completely parallel the existing PGT system.

A 36–inch O.D. pipeline, without any new compression, from Malin, Oregon to Antioch, California. These facilities would be constructed and operated by Pacific Gas and Electric Company (PG&E) and would completely parallel the existing PG&E system from Malin to Antioch.

A 36–inch O.D. pileline from Antioch to Brentwood, California (approximately eight miles) to deliver Alaskan gas to the PG&E system.

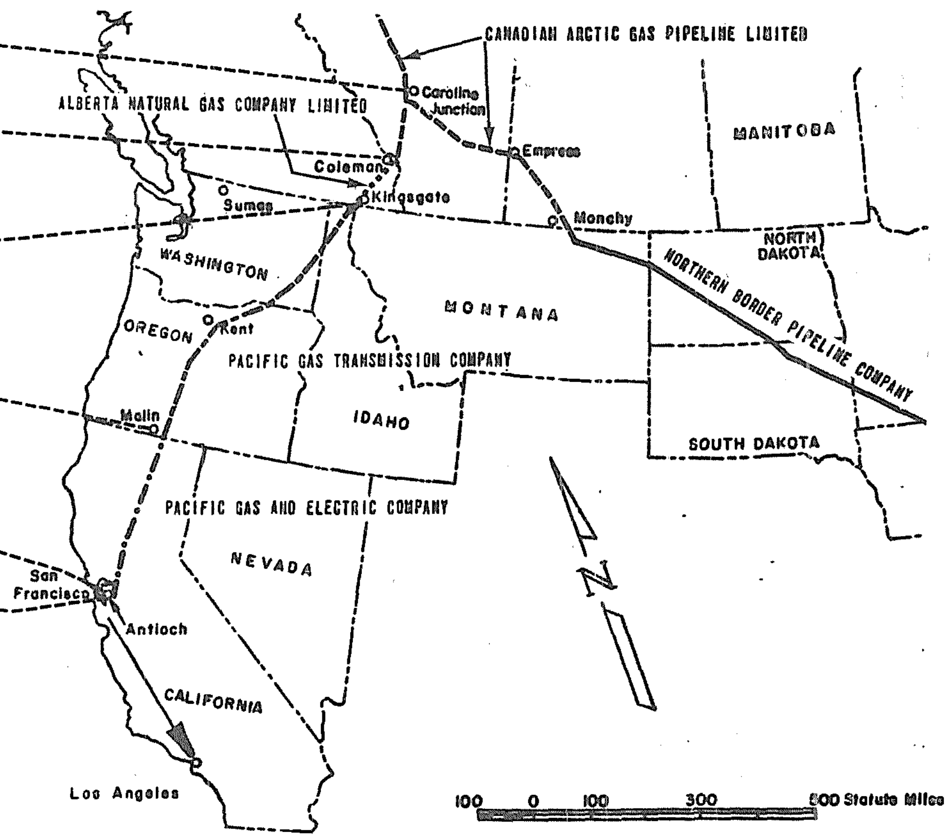
If no gas supplies from other pending supplemental gas projects, such as Indonesia or Cook Inlet LNG, is available at the time the Artic Gas project commences operation, thereby preventing exchanges of gas purchased by Pacific Interstate Transmission Company (Pacific Interstate) between the PG&E system and the Southern California Gas Company (SoCal) system, PG&E would construct an additional 120 miles of 30–inch O.D. pipeline to transport Pacific Interstate's gas into SoCal's system.

1/ Ref: Brief of the People of the State of California and the Public Utilities Commission of the State of California, September 29, 1976 (p. 2).

2/ Under Alcan's 48" Alternate System, this segment would be a 36" OD low pressure line, and would be constructed and operated by Alberta Gas Trunkline (Canada) Ltd.

3/ Under Alcan 48" Alternative System, these facilities would be constructed and operated by Westcoast Transmission Corporation, Ltd.

NOTE: The Western Leg Description stated above refers to the "1580 Design" (See Text and Exhibits IX-2 and IX-3).



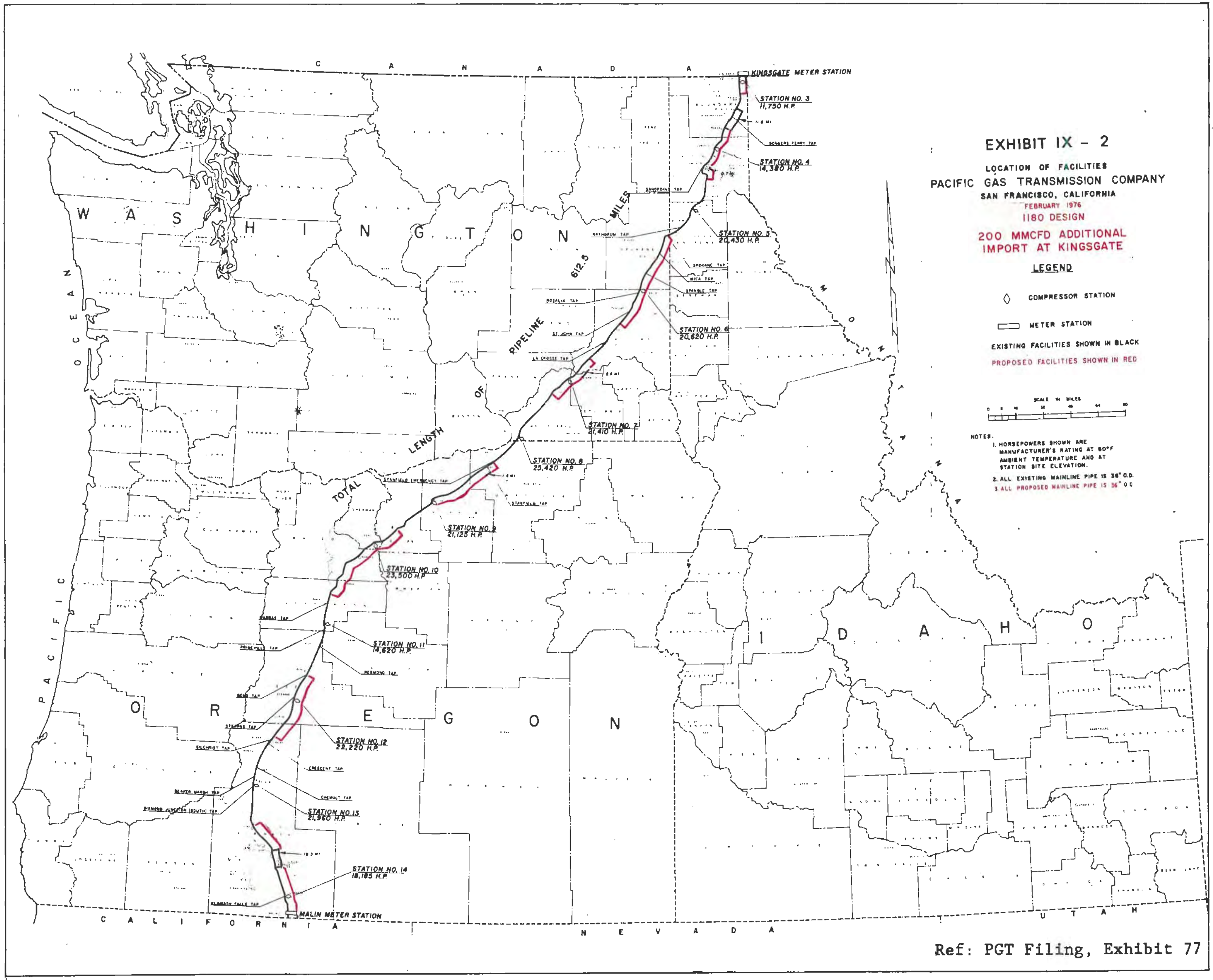
LEGEND

- CANADIAN ARCTIC GAS PIPELINE LIMITED
- NORTHERN BORDER PIPELINE COMPANY
- ALBERTA NATURAL GAS COMPANY LIMITED
- PACIFIC GAS TRANSMISSION COMPANY
- PACIFIC GAS AND ELECTRIC COMPANY

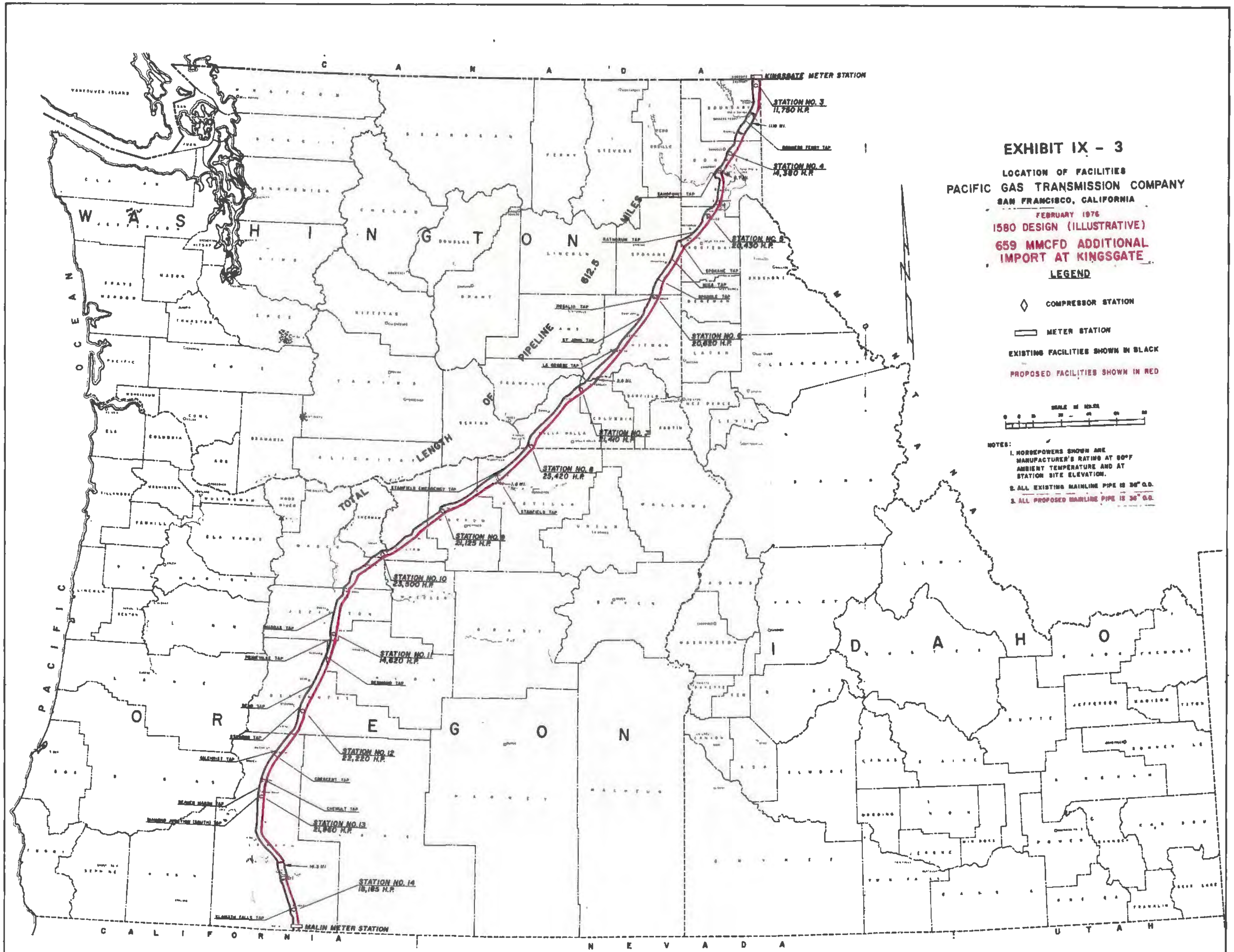
EXHIBIT IX - 1

WESTERN LEG OF THE PROPOSED ARTIC GAS SYSTEM AND THE ALCAN 48" ALTERNATIVE SYSTEM

Map redrawn from Exhibit AA-146



Ref: PGT Filing, Exhibit 77



Ref: PGT Filing, Exhibit PG-94.

C. The Principal Arguments

The State of California supports the western leg. California argues that studies prepared by the FPC staff, purportting to show a $49 million annual savings from displacement as compared to constructing the new western leg facilities, ignore the fact that compressor fuel requirement under displacement would result in a loss by western consumers of four to eight percent of the Btu value of the gas to be delivered. This loss of energy would, according to California, have to be compensated by the use of other energy sources such as oil or electricity. With respect to the cost comparison of direct delivery versus displacement, California stated in part, as follows:

> "witnesses for PGT and California hesitated when when asked whether they would favor displacement over a direct delivery system, if it could be shown that displacement would save the California consumers 9 cents per Mcf. First, the evidence of record indicates that displacement may not result in any savings to the California consumers compared to a direct delivery system. Assuming arguendo, however, that a displacement scheme did result in savings of 9 cents per Mcf to the California gas consumers, CPUC Commissioner Ross noted that such a savings would be a small insurance premium, based on the projected price of North Slope gas, for a guarantee of direct delivery of initial and subsequent volumes of gas from the Arctic regions." 5/

The major gas distribution companies in California also support the western leg:

5/ Responding of the People and the Public Utilities Commission on the Western Lateral to California. (p. 4).

"From the beginning PGandE's and So Cal's participation in the Arctic Gas Project has been premised upon the need for a project beneficial to both the east and the west which would provide California with direct access to Alaskan North Slope gas on an equal basis with other major gas consuming areas around the country. The design of the proposed Arctic Gas Project, with delivery legs serving the western and eastern portions of the nation, answers this need." 6/

The FPC staff opposes construction of the new facilities for the western leg on the basis that the proposed facilities are not required because idle capacity may exist on the existing facilities in the near future. Staff argues that (1) Canadian gas exports are expected to decline in the future, (2) new "lateral facilities" to specific market areas should not be certificated without gas purchase contracts, and (3) displacement is a superior alternative to the western leg. Staff suggests at least deferring a decision on the issue to a later stage of these proceedings, or approving the "lowest-cost, least risky new facilities," the so-called "1180" design.

The Conservation Intervenors 7/ opposed construction of the western leg, on grounds that the facilities are not needed, that construction would adversely affect the environment, and that not constructing the facilities would save money.

6/ Joint Statement filed by Pacific Gas and Electric Company, Southern California Gas Company, and San Diego Gas and Electric Company; June 23, 1976 (pp. 2-3).

7/ Sierra Club, The Wilderness Society, National Audubon Society, and Alaska Conservation Society.

Judge Litt found that "authorization of a western leg for the Arctic Gas Project if certificated, is required by the present and future public convenience and necessity," and that the "displacement alternative espoused by the staff, predicated as it is upon what presently appears to be an unduly pessimistic view respecting Canadian curtailments and justified on the basis of transportation cost savings which may be largely illusory, cannot be considered a preferable alternative on this record." 8/ He concluded by noting "[e]veryone must recognize that significant changes in circumstances can occur by [the time construction commences]... which may dictate adjustments in the sizing or design of any portion of the approved transportation system." 9/

Finally, in oral argument, Alcan stated that deferral of a new facilities decision on the Western Leg was reasonable.

D. Assumed Volume of Gas to be Transported Over Western Leg

Most projections are that roughly 30 percent of Alaskan gas will be destined for the western states and 70 percent for the midwestern and eastern states. This assumed division is based upon the division reflected in the advance payments agreements between purchasers and producers. However, FPC has determined that those advance payment agreements are contrary to the public interest:

> ". . . we agree with those parties who in their comments, and at oral argument, opposed this Commission's Alaskan advance payment program as being contrary to the national interest in permitting a few pipelines, among others, to tie-up almost all of the Alaskan natural gas reserves, to the exclusion of others, through advance payments with little or no benefit to the ultimate consumer." 10/

8/ I.D., 279

9/ I.D., 280

10/ RM74-4, December 31, 1975.

Alcan noted in its Brief on Exceptions that "if reality departs from [the assumed division of gas volumes], . . . modifications will be required to reflect the actual situation." Since no sales contracts have been entered into, the "actual situation" of the division of Alaskan gas volumes between the various regions and states cannot be determined now. Any attempts to establish definitively the division of Alaskan gas would require that the FPC, in effect, set up a mandatory gas allocation program. Such a measure is neither required nor desirable at this time. The final division of Alaskan gas to the various regions and states will not be known until gas sales contracts have been tendered to the Commission and certificates of public convenience and necessity have been issued.

E. Future Imports from Canada

Gas imports from Canada play a critical role in determining whether existing pipelines will need to be expanded to provide Alaskan gas to the western states. The extent of future idle capacity on the existing transmission systems from Canada is solely dependent upon the level of exports permitted by the Canadian government and authorized by the Federal Power Commission. A detailed analysis of existing Canadian natural gas export authorizations is shown on Exhibit IX-4. Of particular significance to the western leg issue are the export license expiration dates of December 10, 1981, October 31, 1985, and October 31, 1986, for the GL-4, GL-35, and GL-3 exports, respectively. If these export licenses expire on their scheduled dates, idle capacity will exist on the gas importation system at Kingsgate, B.C. PGT's system would have idle capacity of approximately 140 MMcf/d in December of 1981, 325 MMcf/d in October of 1985, and 745 MMcf/d in October of 1986. If Canada should curtail deliveries under other currently outstanding export licenses as well, idle capacity would further increase.

We believe market and supply findings by the Canadian National Energy Board are required to assess properly future idle capacity that may be available on existing gas transportation systems (PGT and Northwest in particular) for bringing Alaskan gas to the western states. We have no basis for making a definitive determination as to the level of Canadian gas exports that will be available in the future to the United States. However, it would be unwise to ignore some recent trends in Canada's projected imbalance of demand over supply. We note, further, that if Alaskan gas were to be sold to the west coast and mountain states in proportion to their current share of U. S. interstate consumption, approximately 25 percent of the 2.25 Bcf/d or 560 MMcf/d of capacity would be needed to carry the gas; this amount is less than the projected excess capacity by the end of 1986 if existing Canadian export authorizations are not renewed. Of course, Canada's future gas export policies could be effected by, among other things, Canada's decisions respecting the timing and method of transporting Mackenzie Delta gas.

EXHIBIT IX-13

CANADIAN NATURAL GAS EXPORT AUTHORIZATIONS

U. S. Importers	NEB. Export License No.	Lisence Expiration Date	Authorized Annual Volume (MMCF)	Authorized Average Day (MMCF)
Interstate				
Great Lakes Gas Transmission Co.	GL-20	10-31-91	32,100	88.0
	GL-37	10-31-91	71,663	196.3
	GL-43	10-31-91	17,000	46.6
			120,763	330.9
Intercity Minnesota Pipeline Ltd.	GL-28	10-31-95	337	1.0
	GL-29	10-31-95	7,715	21.1
			8,052	22.1
Michigan-Wisconsin Pipeline Co.	GL-38 2/	10-31-90	18,300	50.1
Midwestern Gas Transmission Co.	GL-1	5-14-81 3/	74,000	202.7
	GL-18	10-31-89	52,300	143.3
	GL-39	10-31-90	2,635	7.2
			128,935	353.2
Northwest Pipeline Corp.-Sumas	GL-41	10-31-89	281,359	770.8
Kingsgate	GL-4	12-10-81 4/	51,000	139.7
Pacific Gas Transmission Co.	GL-3	10-31-86	153,270	419.9
	GL-16	10-31-89	74,830	205.0
	GL-24	10-31-93	77,900	213.4
	GL-35	10-31-85	67,500	184.9
			373,500	1,023.3
Intrastate				
The Montana Power Co. 5/	GL-5	10-31-86	10,950	30
	GL-17	10-31-89	7,300	20
	GL-25	10-31-91	7,300	20
	GL-36	10-31-85	3,650	10
			29,200	80
St. Lawrence Gas Co.	GL-6	6-30-87	5,520	15.1
Vermont Gas Co.	GL-19	10-31-89	6,500	17.8
	Total Annual Volume ---		1,023,129	2,803.0

1/ Does not include volume exported for later improt to Canada.
2/ For transportation by Midwestern.
3/ Annual volume authorized for 1980 is 32,245 MMcf.
4/ Annual volume authorized for 1981 is 48,066 MMcf.
5/ By order issued May 12, 1976, the National Energy Board authorized Canadian-Montana Pipeline Company to export an additional 5 Bcf of gas for the period May 1976 to May 14, 1977, for delivery to Montana Power Company. This volume is to offset the loss of 20 Bcf in the annual authorized exports resulting from the expiration in 1973 of License GL-8. The additional 5 Bcf represents an accelerated annual rate of take against remaining licenses and does not reflect an increase in the total volumes which Canadian-Montana is currently au authorized to export under the four remaining licenses. Previously the NEB had permitted the delivery of 10 Bcf for the one year period, May 1975 to May 1976.

Ref: FPC Staff Exhibit No. 43.

F. Future Gas Supplies in the Permian Basin Area

Serving the western states by displacement requires both sufficient gas supplies to effectuate a displacement plan and idle capacity to transport the displacement gas. Future gas supplies from the Permian Basin area may be sufficient to meet some or all of the western states' share of Alaskan gas under a displacement plan which utilized the Permian Basin as the origin of gas for the western states. Under such a displacement plan, other pipelines would reduce their takes from this area and offset this reduction by increasing the amount of gas they would take from the Northern Border system. The increase could be accomplished either through direct deliveries from Northern Border or through exchange agreements with pipelines having direct access to the Northern Border system.

The FPC National Gas Survey Report projects that Permian Basin gas supplies could range from 6.2 to 7.3 Bcf/d, 5.2 to 7.4 Bcf/d, and 4.3 to 7.1 Bcf/d for years 1980, 1985, and 1990, respectively (see Exhibit IX-5) El Paso Natural Gas Company (El Paso Natural) and Transwestern Pipeline Company (Transwestern) jointly purchased approximately 37 percent of the total Permian Basin gas supplies during 1975. 11/ Other interstate pipelines took approximately 23 percent of the total Permian Basin gas production, with the remainder going intrastate. 12/ If it is assumed that the historic 60 percent share is a reasonable projection for the future interstate take and that El Paso Natural's and Transwestern's combined take of approximately 37 percent of Permian Basin gas supplies during 1975 holds for the future, there would appear to be sufficient

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11/ Natural Gas Flow Patterns 1975, Geographic Flow Patterns and Intercompany Relationships, FPC, February 1975. The Permian Basin area is defined differently in the National Gas Survey and Natural Gas Flow Patterns reports, but this difference is not large enough to affect the conclusion herein.

12/ Statement of Gordon K. Zareski, Chief, Resource Evaluation and Analysis Division, Bureau of Natural Gas, FPC, Hearings before the Subcommittee on Energy and Power of the Committee on Interstate and Foreign Commerce, U.S. House of Representatives, March 24, 1977 (Table No. 8).

EXHIBIT IX-5

ESTIMATED FUTURE GAS SUPPLIES FROM THE PERMIAN BASIN AREA (BCF/D)

	Actual	Projected			
	1970	1975	1980	1985	1990
Case I	8.1	7.6	6.2	5.2	4.3
Case II	8.1	7.7	6.6	5.7	4.9
Case III	8.1	7.8	7.1	6.8	6.4
Case IV	8.1	7.8	7.3	7.4	7.1

Ref: Federal Power Commission; National Gas Survey, Volume 1, FPC Report (1975); Table 9-39, p. 271.

Note 1. Case I assumed that there would be little or no change from the current trends.
Case II was considered the "conservative realistic situation.
Case III was considered the "optimistic realistic situation."
Case IV represented the maximum future supply that could reasonably be expected to be available.
For a more complete description of these cases refer to pages 261-263 of the above cited reference.

Note 2. The "Permian Basin Area" as defined in this report corresponds to National Petroleum Council Region 5.

gas available to interstate pipelines from this area to effectuate a displacement plan. It is conceivable that at least 1.0 Bcf/d could be displaced westward by 1990, which is greater than the 0.659 Bcf/d gas volume entitlement assumed by the western states to be their share of Alaskan gas. 13/ Thus by shifting 659 Bcf/d from other interstate lines to El Paso Natural and Transwestern, the displacement could be done.

While the above analysis is inherently speculative, it illustrates the general range of gas supplies available for displacement.

G. Projected Future Idle Capacity on Existing Permian Basin/San Juan Basin-to-California Gas Transportation Systems

The second ingredient of a successful displacement plan is sufficient idle capacity on existing transportation systems. Because of declining gas supplies in the southwest, idle capacity exists now on the gas transmission facilities to the western states of both El Paso Natural and Transwestern. The idle capacity in all likelihood will be a permanent feature of the El Paso Natural and Transwestern systems, as well as many other pipelines, and is expected to increase in the future.

El Paso Natural obtains approximately 62 percent of its gas supply from the Permian Basin area, 30 percent from the San Juan Basin area, 8 percent from the Panhandle-Anadarko area. Approximately 80 percent of the El Paso Natural gas sales are now made to California transmission and distribution companies at the California-Arizona border. The balance of their gas is sold in West Texas, New Mexico, and Arizona.

13/ That is, at least (.60-.37) x 4.3 Tcf is available for displacement. The entitlement volume assumed by the western states is predicated upon a total available volume of 2.25 Bcf/d from Prudhoe Bay.

Transwestern purchases approximately 80 percent of its gas supply in the Permian Basin area and the remainder in the Panhandle-Hugoton area. Approximately 75 percent of Transwestern's gas moves west to California markets, and approximately 25 percent of its gas is sold to Cities Service Gas Company in the Panhandle-Anadarko area. El Paso Natural has projected that its gas supplies in 1982 would be approximately 2.26 Bcf/d (1.89 Bcf/d from presently dedicated sources and 0.37 Bcf/d from new sources). Transwestern has projected that its gas supplies in 1982 would be approximately 0.45 Bcf/d (0.32 Bcf/d from presently dedicated sources and 0.13 Bcf/d from new sources). The current westward capacity of the El Paso Natural and Transwestern system is 4.0 Bcf/d and 0.75 Bcf/d, respectively. 14/ Therefore, the projected idle capacities commencing 1982 on the El Paso Natural and Transwestern systems are approximately 1.7 Bcf/d (4.0-2.26 Bcf/d) and 0.3 Bcf/d (0.75-0.45 Bcf/d), respectively.

El Paso Natural currently has pending before the FPC an application to abandon a portion of its east-to-west gas transportation facilities and convert it to a crude oil transportation system. 15/ These oil transportation facilities would be utilized to transport Alaskan North Slope crude oil unloaded from tankers at Long Beach, California, to refineries in the southwestern United States.

Under "Phase I" of the proposed abandonment, one 30-inch loop of the El Paso Natural California Mainline system would be converted; under "Phase II" another 30-inch loop of the same line would be converted. El Paso Natural stated in its abandonment application that conventional gas supplies available to its system will decline from 4.0 Bcf/d in 1974 to approximately 1.4 Bcf/d in 1990. This projection by El Paso Natural included annual reserve additions of 220 Bcf, which "represents an optimistic prediction of natural gas additions in future years." 16/

14/ I.D., 282-83.

15/ FPC Docket No. CP75-362.

16/ Initial Brief of El Paso Natural Gas Company, Docket No. CP75-362 (p. 16).

Details of the El Paso Natural idle capacity both with and without the proposed conversion of Phase I facilities are shown on Exhibit IX-6. These data indicate that even with conversion of the Phase I facilities to oil transportation, El Paso Natural's remaining gas transportation facilities would still have idle capacity of approximately 0.5 Bcf/d in 1977 and 1978, and approximately 0.7 Bcf/d in 1979. These excess capacities are sufficient to deliver a significant share of the western states' purchase of Alaskan gas by displacement.

H. Summary and Conclusion

Sufficient information is not available to make an informed judgment as to the extent of idle capacity that may occur in the future on existing gas importation systems as a result of changes in the level of gas exports from Canada. Additionally, the division of Alaskan gas between the various regions and states is unknown at this time. It would not be in the public interest to construct new large-capacity facilities to serve the western states if those facilities would be efficiently utilized for only a short time.

The future level of gas exports from Canada will be determined by the Canadian government. Canada's views and plans must be known to enable us to make a determination of how much idle capacity may be available on present gas importation systems when Alaskan gas becomes available. These decisions may be affected by the timing and procedures Canada selects for developing its frontier gas supplies. If no new export licenses are granted and existing licenses are not extended, substantial idle capacity will be available on the existing transportation facilities. Furthermore, sufficient gas supplies and adequate transmission system capacity will exist, at least in the near term, to deliver by displacement a part of the western states' share of Alaskan gas.

EXHIBIT IX-6

Projected Excess Mainline Capacity on
El Paso Natural Gas Company System
Before and After Proposed Conversion of
Certain Facilities to Oil Transportation Service [1/]
(Peak Day Volumes - MMCF/D)

	1977	1978	1979
Existing Excess Capacity of Mainlines Extending From Permian Basin	827.00	859.00	1,047.52
Existing Excess Capacity of Mainlines Extending From San Juan Basin	375.30	336.20	354.90
Total Existing Mainline Excess Capacity	1,202.30	1,195.20	1,402.42
Excess Capacity of Mainlines Extending From Permian Basin After Proposed Conversion	144.00	176.00	364.52
Excess Capacity of Mainlines Extending From San Juan Basin After Proposed Conversion	375.30	336.20	354.90
Total Mainline Excess Capacity Remaining After Proposed Conversion	519.30	512.70	719.42

1/ Projections made by El Paso Natural Gas Company. Ref: Filing by El Paso Natural Gas Company in FPC Docket No.CP75-362 (Exhibit V, Sheet 3). See text for description of proposed conversion of gas transportation facilities to oil transportation facilities.

Finally, the lead time required for constructing the western leg is from 2 to 2-1/2 years, as compared to the estimated completion time for Alaskan gas transportation systems of from 4 to 5 years.

Thus, our recommendation is to defer for one to two years the certification of any new facilities for the western leg portion of a Canadian-U. S. overland gas transportation system. We believe the western states will not be disadvantaged or denied access to their share of Alaskan gas by this deferral. We are mindful that direct access to Alaskan gas must be provided both east and west of the Rocky Mountains, and we believe this deferral is consistent with the legislative mandate. When the final gas transportation system is "fined-tuned," in a subsequent phase of these proceedings, attention should be focused on overall costs to consumers, fuel efficiency of the systems, and operating flexibility in determining the best method for providing direct access to Alaskan gas for the western states.

CHAPTER X

COMPETITIVE IMPACT ASSESSMENT

A. Introduction

The Alaska Natural Gas Transportation Act requires the FPC to assess the "impact upon competition" for "each transportation system reviewed or considered." 1/ The language of the Act encompasses competition between regulated gas pipelines, both in gas supply and regional demand markets, and competition among gas, oil, coal and electricity. Here we focus on competition among gas pipelines. In Chapter XI we consider the impact of the proposed transportation systems on competition between types of fuel.

Ideally, an assessment of competition between pipelines would require answers to the following questions:

- Which U.S. pipeline and distribution companies will obtain the Alaskan gas?

- How much will the Alaskan gas cost?

- Will it be priced separately or averaged with other supplies?

- How will transportation costs vary among the three proposed routes?

- Will the transportation services be priced on an average or separate basis?

1/ Section 19 of the Act also directs the Attorney General "to conduct a thorough study of the antiturst issues and problems relating to the production and transportation of Alaska natural gas."

- Under what conditions are neighboring pipelines likely to compete for sales?

With few exceptions, the information needed to answer these questions is not available. Our assessment of the competitive impact of the proposed transportation routes must, therefore, be judgmental.

B. The Competitive Nature of Pipeline Markets, Displacement Schemes, and the Purchase Restrictions on Alaskan Gas

In antitrust law, competition is said to occur when there is rivalry among sellers for larger market shares. Pipeline companies usually operate in regional markets which are oligopolistic, that is, markets in which there are few sellers. 2/

Regional markets served by pipelines are different from textbook oligopolies in two important respects. First, the oligopolistic market of conventional economic theory presumes an absence of regulation. This presumption is inappropriate to any discussion of natural gas pipelines

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2/ The term "regional pipeline markets" refers to specific geographic markets in which pipeline companies are the sellers and gas distribution companies are the buyers. Radford L. Schantz, a witness for Arctic Gas, stated that there are "many regional markets" (Tr. 28,650) and that the principal ones are coterminous with the states of Ohio, Michigan, New York, Pennsylvania, and California. Schantz' testimony focused on how interfuel competition might affect the marketability of Alaskan gas. He did not consider the potential for competition among pipelines, nor to the best of our knowledge did any other witness. We agree with Schantz that pipelines compete in regional markets. We are not convinced, however, that state boundaries are useful for delineating these regional markets since they are extensively regulated with respect to the prices they can charge and the markets they can enter. 3/

A second characteristic of pipeline markets which differs from the textbook oligopoly is that competitive activity tends to be sporadic. Gas distribution companies and industries, the principal pipeline customers, are usually tied to their supplier by long-term contracts.

Competition is further hindered by the fact that natural gas pipelines, unlike petroleum pipelines, are not common carriers. A gas pipeline must be physically connected to a potential customer in order to deliver contracted volumes. When a gas distribution company is connected to two or more pipelines, switching purchases from one pipeline to another is a relatively simple matter, and competition is possible. In the more common situation, however, a potential customer is not connected to the pipeline that is seeking to increase its sales. The potential supplier then has to incur the cost of constructing a spur from his principal supply, a requirement which, in some degree, limits competition. In both cases, Federal Power Commission approval is required for the transfer of sales.

3/ It is interesting to compare our regulation of natural gas pipelines with the Interstate Commerce Commission's regulation of petroleum pipelines. Both agencies are required to regulate the prices charged by pipelines. In addition, natural gas pipelines are required to get our permission to build or abandon a facility (i.e., to enter or leave a market). Petroleum pipelines, however, can undertake either action without obtaining ICC approval. Furthermore, with the exception of the Alaskan gas transportation system, Congress has never ordered natural gas pipelines to be operated as common carriers. In contrast, all petroleum pipelines under ICC regulation are required to function as common carriers.

In an oligopolistic market, both price and nonprice competition may exist. The latter occurs most frequently when sellers are not allowed to lower their price below some minimum. Since they are prevented from obtaining additional sales through lower prices, sellers may try to capture sales by offering more services than their competitors. Nonprice competition is somewhat rare in regional pipeline markets. 4/ Most cases adjudicated by the Federal Power Commission have involved price competition. 5/

Pipeline companies and, to a lesser extent, distribution companies also participate in another market, the market for gas supplies. In this market, pipeline companies are the principal buyers and oil companies and independent natural gas producers are the sellers. The market for

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4/ We are aware of two cases that might be considered examples of nonprice competition. In 1956, Pacific Northwest, a potential pipeline supplier to the California market, offered both lower prices and an uninterruptible service during peak periods to the Southern California Edison Co. which was then being supplied by El Paso Natural Gas Co. on an interruptible basis. El Paso was able to retain Edison's business by countering with a similar offer of uninterruptible service (see 376 U.S. 654, 659). In another case, the Atlantic Seaboard Corporation offered a winter storage service to the Washington Gas Light Co. only after Washington had received a similar proposal from a potential competitor, the Transcontinental Gas Pipeline Corp. (see 397 F.2d 753). The common element in both of these cases was that the potential supplier was willing to offer a type of service that was not available from the existing supplier.

5/ See n. 19, Chapter X, for a listing of some of the more important cases involving price competition.

Alaskan gas can be viewed as a sub-market within the large gas supply market. Most U.S. pipeline companies are potential buyers in the Alaskan market. Four sellers, the State of Alaska, Exxon Company USA, Atlantic Richfield Company, and Sohio Petroleum Company, dominate the supply side of the market. Their control of Alaskan gas supplies could under certain circumstances lead to joint monopoly pricing. In Chapter XII we discuss a formula approach for pricing Alaskan gas which, if adopted, would reduce the ability of the four sellers to exploit their dominant market position. Incremental pricing would also achieve this result.

1. Displacement Agreements and Competition

Traditional governmental policies aimed at influencing competition in an oligopoly market fall into two categories: those which affect market conduct and those which affect market structure. Market conduct refers to "the patterns of behavior that enterprises follow in adapting or adjusting to the markets in which they sell." 6/ More specifically, market conduct encompasses the aims and methods used by sellers in "establishing what prices to charge, what outputs to produce, what product designs to choose, what sales-promotion costs to incur . . . ." 7/ Price fixing, market sharing, and output restrictions are examples of collusive market behavior and such collusive activity is usually considered illegal.

The need for closely coordinated displacement agreements could create the potential for collusive market conduct. Yet, if the ownership of Alaskan natural gas is to be widespread, as

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6/ Joe Bain, Industrial Organization, New York: John Wiley & Sons, Inc. 1968, p.9.

7/ Ibid.

we recommend elsewhere, then transportation economics and the location of existing facilities dictate delivery by displacement for some gas under each proposed transportation system, especially El Paso's system. El Paso's extensive displacement scheme is a clear departure from traditional pipeline practice in which each pipeline transports its own gas in its own system and builds facilities as needed.

Displacement reduces the miles of pipeline that have to be built within the lower 48 states, thus minimizing both private and environmental costs. Displacement procedures will not work, however, without close cooperation between neighboring pipelines. Therein lies the problem. It is difficult to expect two pipelines to coordinate and compete at the same time. 8/

8/ Essentially the same problem presents itself in the electric utility industry. Considerable savings can be achieved through power pooling but these savings probably come at the cost of reduced competition between electric utilities in the bulk power supply market. Alfred Kahn, Chairman of the New York State Public Service Commission, describes the problem in the following way: ". . . the arrangement of power pooling, or joint use of facilities requires constant communication between firms that are in important respects also competitors or potential competitors. It is very difficult to encourage companies to cooperate in such delicate matters as setting joint rates, the sharing of business, and the planning of investment while insisting that they compete vigorously in other respects . . . ." He goes on to note that ". . . there is a strong tendency for these collaborative efforts to turn into instruments for the collusive suppression of competition among the participants . . . ." Alfred E. Kahn, The Economics of Regulation, Vol. II, New York: John Wiley & Sons, Inc. 1971, p.69.

Displacement technology offers the benefit of almost certain cost savings to American consumers. Pipeline competition within a region may also reduce costs. But we are much less certain about the magnitude of potential savings from this form of competition. We do not know how much competition can be generated by the actions of this Commission. Nor do we know what minimum threshold of competition is needed to induce price reductions. We believe that savings to consumers are likely to be greater from displacement arrangements than from attempts to induce competition among pipelines in a region by disallowing displacement and requiring new pipeline facilities to transport Alaskan gas to purchasers.

We do not believe that the displacement procedures proposed by any of the applicants are in violation of the antitrust laws. But we are mindful that the negotiations required to implement these procedures could produce agreements of a noncompetitive nature beyond those necessary to effectuate the procedures. The use of displacement cannot be allowed to serve as a vehicle for the proliferation of restrictive practices. We will permit only those practices which are indispensable to the successful operation of the displacement procedure.

2. Market Structure Policies and Gas Allocation

Market structure policies refer to actions taken by the government that affect either the number or size of sellers in a market. The general belief is that the larger the number of sellers and the more equal their size, the greater the competitive pressures. With regard to Alaskan gas, little can be done to affect the number of pipeline companies serving existing regional markets. There is, however, the possibility of affecting the market shares of existing pipeline companies serving various regions.

Alaskan gas constitutes an important source of increased supply. Judge Litt estimated that Alaskan natural gas will constitute about 5 percent of total U.S. natural gas production in 1985. 9/

Several criteria could be used in allocating Alaskan gas. One alternative would be to place the gas where it is needed most by applying the Commission's system for assigning priority classes to pipelines. A second approach would be to let free market forces work and to allow all purchases. A third alternative is to attempt to stimulate competition by allocating gas to pipeline companies with small shares in various regional markets in order to improve their ability to compete.

We reject the first approach since by 1985 gas supplies are expected to be serving the highest priorities in virtually all systems throughout the country. We have serious reservations regarding the impact of the second method with regard to system reliability and because we do not believe it would be conducive to a private financing of the transportation system. 10/ The last approach presents the practical difficulty of delineating regional markets. The methods currently available involve considerable subjective judgment. 11/ Further, there is no assurance that smaller companies would necessarily become "stronger" competitors even if Alaskan gas went to them. They might

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9/ *Id.* 303-304.

10/ The relationship between distribution and financing is detailed in Chapter XII.

11/ See Kenneth G. Elzinga and Thomas F. Hogarty, "The Problem of Geographic Market Delineating In Antimerger Suits," *Antitrust Bulletin*, Spring 1972, pp. 45-81.

be disinclined or unable to compete against neighboring pipeline companies. Much would depend on the city-gate price of Alaskan gas relative to the price of gas from other sources. If gas arriving from Alaska is relatively expensive, a small pipeline will, if anything, be at a competitive disadvantage if forced to take large amounts of this gas. Therefore, the efficacy of using allocations to enhance the competitive position of small pipelines is, at best, uncertain.

3. Widespread Distribution of Gas and Competition

We intend to utilize our authority to certificate sales to insure widespread distribution of Alaskan gas. 12/ While the primary intentions of these conditions are to (1) limit the degree of reliance of any pipeline system or distribution company on Alaskan natural gas, (2) provide a broader incentive to participate in displacement arrangements, and (3) make a private financing of the transportation system easier to accomplish, we also recognize that such conditions may affect the competitive structure of the industry. 13/

12/ Administratively, this objective could be achieved in at least two ways. The Commission could indicate in advance that it will not approve a sales contract for Alaskan gas if it appears that the Alaskan gas will constitute more than, for example, 10 percent of the purchasing system's total supply of gas.

13/ While Chapter XII deals with the effects of broad distribution of ownership upon system reliability and financeability, the effect on displacement arrangements needs further elaboration. The successful implementation of a displacement plan requires that there be a coincidence of interests among the participants. The Department of the Interior, in its report to Congress, stated:
(footnote continued on next page)

In order to know the competitive impact of a broad distribution of Alaskan natural gas, we have to look at two markets, the regional markets in which pipelines act as sellers and the gas supply market in which pipelines participate as buyers. Our best information is that a broad distribution of Alaskan gas will have a neutral impact on competition between pipelines in regional markets. Under such a distribution plan, no pipeline will receive more than a small portion of its total gas supply from Alaskan gas. Since the Alaskan gas will be averaged in with much larger quantities of gas from other sources, it will have a minimal impact on the overall supply costs of any pipeline. It is unlikely, therefore, that the Alaskan gas will affect the ability of one pipeline company to compete against another.

Assessing the competitive impact of a broad distribution plan on the Alaskan gas supply market is somewhat more difficult. Evidence suggests that the Alaskan gas supply

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13/ (Continued from prior page)

> ". . . if most of the companies involved in the displacement arrangement are purchasers of Alaskan natural gas or have some other incentive to quickly reach an agreement on displacement, such as being an investor in the Alaskan natural gas transportation system, then the private companies involved could probably quickly reach some agreement on a displacement plan. However, if displacement involved a company which was neither a purchaser of the Alaskan gas nor an investor in an Alaskan natural gas transportation system, then such a company may not be inclined to enter into a displacement agreement which might cause delays in the completion of this system."

U.S. Department of the Interior's Alaska Natural Gas Transportation System (1975), p.141.

market has not operated competitively in the past. This evidence includes the pre-1976 transactions in this market which occurred without any direct Federal interference. These transactions generally resulted in purchases of entitlements by a limited number of pipelines and gas distribution companies. 14/ Almost all of the entitlements went to the sponsors of the Arctic Gas proposal. 15/

Most of the entitlement agreements included substantial advance payments, and some of the smaller pipeline companies may not have been able to raise the capital needed for such payments. 16/ Thus, the entitlement transaction itself may have constituted a "barrier to entry" for many potential buyers. Additionally, some gas distribution companies may not have participated because their state regulatory commissions were unwilling to approve of such transactions. If the market had operated without an advance payment program, these financial and institutional "barriers to entry" would have disappeared and it is conceivable that a much broader distribution of gas would have occurred.

14/ The purchase of an entitlement gives a company the first option to bid for the gas if and when it becomes available at a later date.

15/ A summary of these first round transactions can be found in a table appearing on p.162 of the Interior Department's Alaskan Natural Gas Transportation System report.

16/ See the comments of Mr. James W. McCartney (representing a pipeline group consisting of Texas Gas, Transco, Southern Natural, United Gas Pipeline Company, Florida Gas, Mid-Louisiana, Texas Eastern and Transwestern) and Mr. Stephen Wakefield (representing the United Gas Pipeline Company) and Mr. John T. Miller (representing the Arizona Corporation Commission, the Arizona Public Service Company and Tuscon Gas and Electric Company) on pp. 118, 136, and 145, respectively, of the Oral Argument (October 23, 1975) in Docket Nos. R-411 and RM74-4.

Since the Commission terminated the advance payments program, 17/ it could be argued that the market for Alaskan gas will now operate competitively. We have some strong doubts about the validity of this view. We are concerned about the potential for noncompetitive side agreements that may result from Alaskan gas sales.

Suppose that Alaskan gas is sold at a price which results in demand being greater than supply. The owners of the gas will then be in the position of having to choose among potential buyer on some basis other than price.

We have already seen evidence of this phenomenon. The State of Alaska agreed to sell its royalty gas to El Paso Natural Gas Company, Southern Natural Gas Company and Tenneco Alaskan, Inc., in return for their active support of the El Paso route. Similarly, the oil companies may have sold entitlements to Arctic Gas sponsors in the belief that such contracts might influence this Commission to favor the Arctic Gas route, a route which appears to be more favorable for the development of gas supplies in the Mackenzie Delta controlled by at least one affiliate of the oil companies. Once a route is chosen and certified, these considerations will no longer be relevant. But since many of these contracts have been abrogated as a result of our advance payments decision, the oil companies will once again have to decide among a number of buyers who are not able to compete on the basis of price.

17/ See Order on Remand From Court Opinion Terminating Investigation and Terminating Advance Payment Program With Conditions, Docket Nos. R-411 and RM74-4, December 31, 1975. In this order the Commission terminated rate base treatment for Alaskan advances made under contracts executed on or after December 28, 1973.

In such a situation, there will be an incentive for the oil companies to favor pipeline and gas distribution companies that can provide other benefits. One of these benefits could include an agreement by the buyer that he will not compete against the oil company or the oil company's affiliates in various energy markets. If these agreements do take place, they are likely to be tacit understandings that are not readily observed by government agencies.

Even though the imposition of a plan to produce a widespread distribution of the Alaskan gas is, by its very nature, an interference with the gas supply market, it is possible that the overall impact of this distribution scheme may favor competition. It will have a neutral impact on regional pipeline markets and reduce the likelihood of restrictive side agreements resulting from transactions in the gas supply market.

4. Regulation And Competition

The prices and quantities of gas sold by interstate pipelines are directly controlled by the Federal Power Commission. Commission approval is also required to construct a new interstate pipeline or to abandon an old one. Pipelines are equally affected, though indirectly, by the FPC's regulations of the wellhead price of natural gas. The government's decision as to whether or not the Alaskan gas transportation system is to be a common carrier will also have an impact on competition. These issues involving the competitive influence of Federal regulation are discussed in this section of the report.

a. Pipeline Certification

The Federal Power Commission's authority to certify pipelines is probably the single most important regulatory decision affecting inter-pipeline competition. In deciding whether to issue a certificate, the Commission is required to use a "public interest" standard. The Courts have indicated on numerous occasions that competition is one of several relevant considerations that should be used in defining the public interest. 18/ However, the Commission has interpreted its public interest mandate to mean that competition should not be encouraged exclusive of other considerations. In particular, the Commission has generally not allowed one pipeline, say pipeline A, to take over a customer served by another pipeline (pipeline B) if it appeared that pipeline B's remaining customers would be forced to bear a much greater burden of B's fixed charges. Applying this standard, usually referred to as the "market loss test," the Commission has approved the shifting of loads in some cases while denying it in other. 19/ Given the pessimistic outlook for future gas supplies, we believe there is little likelihood that the Commission's pipeline certification decisions will stimulate competition in the near future.

18/ U.S. v. CAB, 511 F.2d 1315, FMC v. Svenska American Linien, 390 U.S. 238.

19/ The FPC allowed a shift in sales to a new supplier in the following cases: Atlantic Seaboard Corporation v. Federal Power Commission, et al., 397 F.2d 753 (1968) The Cincinnati Gas and Electric Company, et al., v. Federal Power Commission, et al., 389 F.2d 272 (1968), Alabama-Tennessee Natural Gas Company v. Federal Power Commission, 417 F.2d 511 (1969), Kentucky Natural Gas Corp. v. FPC, 159 F.2d 215 (6th Cir. 1947), Home Gas Co. v. Federal Power Commission, 231 F.2d 253 (D.C. Cir.) Lynchburg Gas Co., 24 F.P.C. 955 (1969), Transcontinental Gas Pipe Line Corp., 35 F.P.C. 917. The Commission disallowed a shift in sales in the following cases: Natural Gas Pipe Line Co., 36 F.P.C. 1 (1966), Texas Eastern Transmission Co., 14 F.P.C. 116, Gulf Pacific Pipeline Co., June 26, 1968.

b. Wellhead Pricing

The Federal Power Commission has been required to regulate the wellhead price of natural gas since the Supreme Court's 1954 decision in the Phillips case. However, it is possible that natural gas prices will be deregulated before or during the useful life of the Alaskan gas transportation system. Thus, we have examined the impact on pipeline competition of both regulation and deregulation.

(1) Continued regulation

Under continued regulation, even with all new gas prices set at their free-market Btu-equivalent price, demand will likely exceed supply because the pipelines are likely to be averaging the new gas price with substantial volumes of old, low-priced gas.

Since the pipelines will have insufficient gas to serve the demands of their own customers, they will probably not try to compete for the customers being served by neighboring pipelines. Whatever rivalry occurs will be for additional supplies, such as the Alaskan gas. Pipelines successful in this competition will benefit by being able to supply a larger proportion of their customers' demands. This case differs from the typical competitive situation in that pipelines are competing for supplies rather than customers. As long as gas is regulated at a price where demand exceeds supply, competition for customers among neighboring pipelines will not occur regardless of which Alaskan gas transportation system is certified.

(2) Deregulation or regulation at a price which equates supply and demand

Either deregulation or regulation at a price which equates supply and demand will lead to a higher price for natural gas. Assuming that the higher price is passed on from pipelines to distribution companies to consumers, then excess demand for natural gas will be eliminated.

Under these circumstances competition may occur by one pipeline trying to supply the demands of customers being served by neighboring pipelines. Given the present gas shortage, such competition is difficult to envision. Nevertheless, Federal Power Commission records indicate that this kind of competition has taken place in the past. In numerous instances throughout the 1950's and 1960's, one pipeline would try to take over an industrial or wholesale load being served by another pipeline. 20/

c. Cost Differences and Competition

The potential for competition increases when significant differences occur in operating and purchased gas costs among pipelines. 21/ One pipeline may have lower operating costs because of better management or more efficient design. Purchased gas cost differences can occur if one pipeline obtains access to gas supplies which are significantly cheaper than those purchased by neighboring pipelines.

Whether Alaskan gas provides a competitive advantage or disadvantage for the purchaser depends on the delivered price of that gas relative to other supplies. We believe that under continued regulation or deregulation the gas is marketable. But unlike most other gas supplies, where the time between contract date and initial delivery is short, the interval for Alaskan gas is going to be four to six years. Thus, unless fixed-price contracts are negotiated, the parties will not be able to predict the wellhead price. Furthermore, until the transportation system is built, the cost of service will not be fully known. Without this knowledge, the competitive cost advantage of Alaskan gas is not known.

20/ See n. 19, Chapter X.

21/ Scherer writes that "the more cost functions differ from firm to firm, the more trouble the firms will have maintaining a common price policy . . . ." See Frederic Scherer, Industrial Market Structure and Economic Performance, Chicago: Rand McNally & Company, 1970, p. 192.

d. Effect of "All-Events" Tariff on Price

The possibility also exists that producers can exercise some monopoly power over shippers who are under an all-events tariff which extends beyond the initial sales contract. Knowing that the shipper must pay the shipping tariff under any condition, even nonshipment, the producer could charge a wellhead price as high as the city-gate value (or cost of alternate delivered gas). While regulation might prohibit the exercise of this unusual market power, the shipper's remedy for this situation is long-term sales contracts and coincident sales and shipping contracts. Potential shippers might heed this warning.

e. Alternate Pricing of the Transportation of Displacement Gas

The city-gate price of Alaskan gas will also be affected by the pricing method used to recover the cost of transporting gas through the pipelines of the lower 48 states. Two principal methods exist for pricing gas transported through displacement. The first is known as the incremental method. Under this procedure the purchaser of the Alaskan gas delivered by displacement is required to pay only "an additional transportation cost adequate to cover the cost of new facilities constructed in the lower 48 pipeline network and for any other increases in the cost of service incurred by the pipeline companies involved in displacement." 22/ The second pricing method is known as the traditional method. It is a full-cost allocation method in which the incremental gas bears a portion of the cost of all facilities. It has been used in earlier U.S. displacement agreements which involved smaller amounts of gas than the amounts expected in any of the Alaskan proposals.

22/ U.S. Department of the Interior, Alaskan Natural Gas Transportation Systems, December 8, 1975, p. 106. Note that the incremental pricing of transportation services does not necessarily require the incremental pricing of Alaskan gas itself.

The transportation charges paid by pipelines in a particular region will vary considerably depending on which method is used. The Interior Department calculated the delivered price of Alaskan gas using the incremental and the traditional pricing methods for two hypothetical systems, an Alaska-LNG system and an Alaska-Canada system. Their calculations are reproduced in Exhibit X-1.

EXHIBIT X-1

DELIVERED GAS COSTS FOR ALASKAN GAS
PRICED BY THE INCREMENTAL AND TRADITIONAL METHODS
OF DETERMINING TRANSPORTATION COSTS
TOTAL GAS COST
¢/MCF

	Alaska LNG System		Alaska-Canada System	
	Incremental	Traditional	Incremental	Traditional
West Coast	260.0	260.0	275.7	314.6
Midwest	272.4	305.3	260.0	260.0
Northeast	279.7	312.8	274.4	313.3

Source: U.S. Department of Interior, Alaskan Natural Gas Transportation Systems, December 1975, Tables 18 (p. 107) and 19 (p. 109).

Consider the case of a pipeline which obtains access to large quantities of Alaskan gas and which serves markets in the Northeast. Under the hypothetical Alaska-Canada system, the average delivered cost for this pipeline will be 274.4 ¢/Mcf under incremental pricing and 313.3 ¢/Mcf under traditional pricing. Suppose that another pipeline serving the Northeast obtains its gas from lower 48 and non-Alaskan supplemental sources at an average delivered cost of 280.0 ¢/Mcf. If the traditional method is used in pricing the transportation of Alaskan gas, the pipeline that is supplied from non-Alaskan sources will have a competitive advantage in Northeast markets. But, under the incremental method, it would lose that advantage.

The example illustrates how a decision regarding pricing methods will influence the cost of Alaskan gas and hence the competitive climate. El Paso's proposed method of allocating incremental displacement facilities cost in Texas has comparable effects. 23/ The Commission has to consider these factors in approving the sales of Alaskan gas and its displacement in subsequent certification.

f. Common Carrier Status and Competition

We interpret Section 13a of the Alaska Natural Gas Transportation Act to mean that Congress wants the Alaskan

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23/ EP-265, p. 43.

gas transportation system operated as a common carrier. 24/ Under most circumstances, common carrier status is desirable because it is pro-competitive. It enables various shippers, who may also be potential competitors, to have equal access to a common transportation route. However, in the case of the Alaskan gas transportation system, we think that common carrier status is incompatible with our goal to effect a private financing.

The presence of a common carrier provision creates an incentive to become a "free rider", and thus provides a disincentive to invest in the system. From a competition perspective we would prefer the common carrier provision be maintained, while from a financing perspective its elimination may be required.

24/ Section 4(5) of ANGTA does not provide a clear definition of what constitutes the Alaskan gas transportation system. A clear definition will be necessary if Congress decides to retain the common carrier provision. One approach would be to include only new physical facilities expressly constructed for the transportation of Alaskan gas. Note that in the case of the El Paso application this definition would also include the Waha-Refugio line in Texas and the LNG terminal in California. Another approach, broader in scope, would include the new physical facilities and all existing lower 48 pipelines that are used in the displacement plan. If this second approach were adopted, we suspect that some pipelines would be unwilling to provide displacement services for fear of being designated common carriers. Congress should also indicate whether the transportation system will serve as a common carrier only for the Alaskan gas or for the Alaskan gas and any other gas that might require access to the system somewhere along the route.

6. Conclusion

It is our conclusion that the certification of a particular Alaskan gas transportation system will not have any significant impact on pipeline competition within the United States. Though the choice of a particular transportation system will affect the cost of Alaskan gas between regions, that choice will not have any significant impact on interpipeline competition between regions because such competition generally occurs within a region.

The competitive impact of the Alaskan gas transportation system will be determined by a complex interaction of economic, regulatory and engineering factors. The two most important factors will be the extensive use of displacement procedures and the imposition of a broad distribution of gas. Transporting Alaskan gas through the lower 48 states by displacement will entail a greater degree of coordination among U. S. pipelines than has existed to date. Such coordination will lessen competition and may even produce restrictive agreements which may be necessary and subsidiary to implementing the displacement procedures, but in other contexts would be unreasonable.

Under a broad distribution plan, the amount of Alaskan gas received by any individual pipeline will be limited. Therefore, whatever impact the Alaskan gas has on overall supply costs will be approximately the same for all pipelines. Consequently, the Alaskan gas will have a neutral effect on competition between pipelines in regional markets. A broad distribution of gas will not have a neutral impact in the gas supply market. Any imposed distribution plan is an interference with the market. Nevertheless, the overall effect of a broad distribution may be competitive if it reduces the likelihood of restrictive agreements in other energy markets.

CHAPTER XI

PROJECTIONS

A. Introduction

Section 5(c) of the Alaskan Natural Gas Transportation Act provides:

> "The Commission shall accompany any recommendation under subsection (b)(1) with a report ... including for each transportation system reviewed or considered a discussion of the following:
>
> (1) for each year of the 20-year period which begins with the first year following the date of enactment of this Act /1977/, the estimated --
>
> (A) volumes of Alaska natural gas which would be available to each region of the United States directly, or indirectly by displacement or otherwise, and
>
> (B) transportation costs and delivered prices of gas by region;
>
> (2) the effects of each of the factors described in subparagraphs (A) and (B) of paragraph (1) on the projected natural gas supply and demand for each region of the United States and on the projected supplies of alternative fuels available by region to offset shortages of natural gas occurring in such regions for each such year; . . .
>
> (10) the estimate of the total delivered cost to users of the natural gas to be transported by

> the system by year for each year of the 20-year period which begins with the first year following the date of enactment of this Act.

While some of this information has developed in the course of the FPC certification procedures, much of it is not contained in the record. Hence staff, under Section 5(b)(3) of the Act requested assistance from the Federal Energy Administration (FEA), since FEA has a projection model which is used in the FEA <u>National Energy Outlook</u>, an annual report with which both the executive and congressional branches of government are familiar.

FEA responded to our request and produced long-term energy supply/demand and price projections under a variety of scenarios. As the April 29, 1977, transmittal letter to our staff from FEA notes:

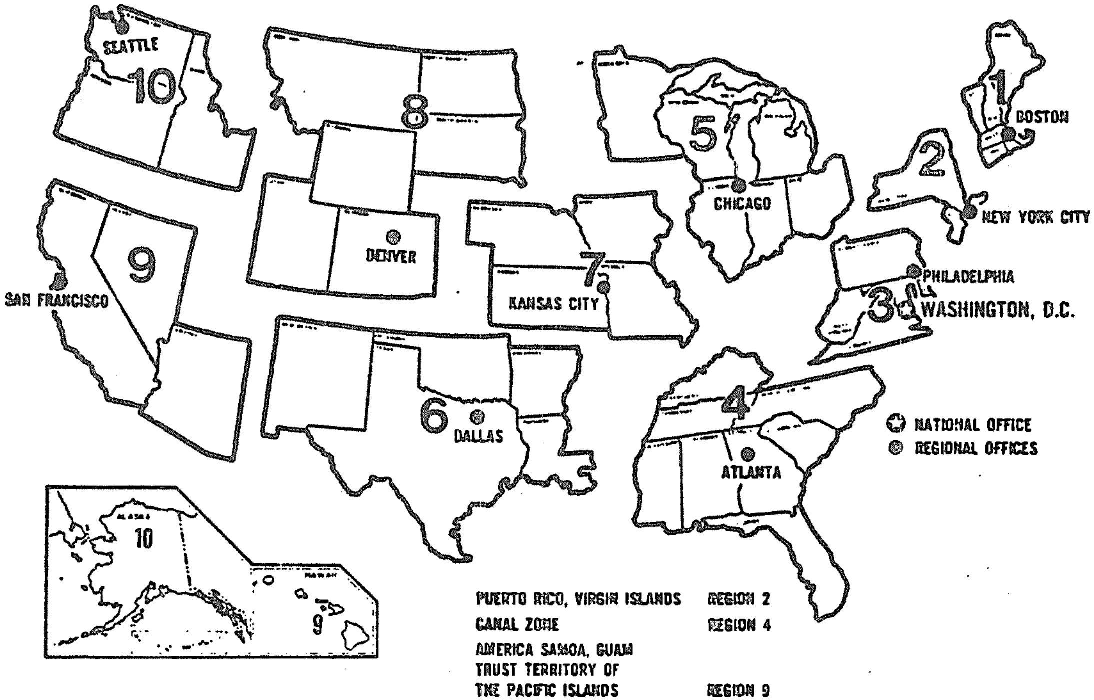
> "[a]n energy model cannot project with certainty the absolute level of energy consumption and prices, but it can give an idea of the effects of certain policies and actions. Therefore, we would suggest that these projections be used in a comparative rather than absolute manner."

We would only add the additional caution that these are projections, not forecasts -- we do not know at this time who will be purchasers of the Prudhoe Bay natural gas. Thus, the results herein can only be considered illustrative.

1. <u>The Model</u>

FEA's Project Independence Evaluation System (PIES) is a complex projection model that we will not attempt to summarize here; it is described in Appendix A of the <u>1977 National Energy Outlook</u>. It does, however, provide regional consumption and shortfall projections by major consuming sectors. Thus, it provides a sound basis for responding to the Act.

The regions are depicted in Exhibit XI-1. Each region has industrial, commercial, residential and electric utility consuming sectors. Production and consumption of all types of fuels are developed by region. The prices are part of the output.



LEGEND

1. New England
2. New York/New Jersey
3. Mid-Atlantic
4. South Atlantic
5. Midwest
6. Southwest
7. Central
8. North Central
9. West
10. Northwest

EXHIBIT XI-1

FEA DEMAND REGIONS

B. Scenarios

We believe that Alaskan gas will not be delivered by any of the proposed systems until 1982 or 1983. Thus, PIES was run for 1980 to provide a base year as well as 1985 and 1990. Each of the systems was characterized in terms of delivered volumes and costs to each of the demand regions, based upon assumed Alaskan field prices of $1.00 and $1.50 per MMBtu. The apportionment of Alaskan gas was done on the basis of relative historical consumption by regions, and is displayed in Exhibit XI-2. FEA examined three basic cases under each price:

(1) Rolled-in Pricing: Continued regulation of the wellhead price of natural gas at current FPC-set rates with the price of Alaskan gas rolled in with that of other interstate gas; intrastate gas prices unregulated.

(2) Incremental Pricing: Continued regulation of the wellhead price with gas consumed in the industrial sector priced on an incremental basis. Gas consumed in the residential and commercial sectors is priced on a rolled-in basis.

(3) Deregulation: The wellhead price of new interstate gas is deregulated.

The assumed price of imported oil was $13 per barrel; imported oil is the energy resource that provides final equilibration in each of the energy markets.

EXHIBIT XI-2

Apportionment by FEA Region

		1	2	3	4	5	6	7	8	9	10	U.S. Total
Arctic:	Percent	1.6	5.2	7.0	11.0	31.8	5.9	5.0	1.1	29.4	2.0	100.0
	Trillion Btu/Yr.	14.2	46.1	62.0	97.4	281.7	52.2	44.3	9.7	260.4	17.7	885.7
El Paso:	Percent	1.0	3.2	4.3	9.4	20.2	16.4	11.0	1.2	31.2	2.1	100.0
	Trillion Btu/Yr.	8.7	27.8	37.3	81.6	175.3	142.3	95.5	10.4	270.8	18.2	867.8
Alcan:	Percent	1.7	5.4	7.2	11.3	32.7	6.1	5.2	1.0	27.5	1.9	100.0
	Trillion Btu/Yr.	15.9	50.4	67.2	105.5	305.3	56.9	48.5	9.3	256.7	17.7	933.5

Arctic: 2.25 Bcfd @ 1138 Btu/cf.
El Paso: 2.3614 Bcfd @ 1130 Btu/cf.
Alcan: 2.40 Bcfd @ 1148 Btu/cf.

C. The Results

Exhibit XI-3 through XI-5 summarize but a small portion of the output from the various scenarios. Exhibits XI-3 and XI-4 are based upon a field price of $1.00, while Exhibit XI-5 illustrates the effects of assuming a $1.50 wellhead price.

Since none of the systems are operational in 1980, our chart for that year (Exhibit XI-3) illustrates only the impact of the three pricing methods, and provides a baseline for the later impact of Alaskan supplies. For 1985 and 1990, we present a separate chart for each pricing method. Each chart shows the amount of consumption and of shortage, as well as projected residential, commercial and industrial prices, in the event that each of the systems is built, and if no system is built.

Obviously, these charts present an enormous amount of data. Three prices and two volumes are presented for each of 297 cases. Under these conditions, only the most cursory of conclusions can be drawn. A few points do stand out.

More gas will be consumed in the United States, and shortages will be smaller, if a system is built. Which system is built has little effect on that fact. However, the apparent impact of the project on supply will be smaller with deregulation, presumably because more non-Alaskan supplies would be stimulated. Conversely, shortages will be smaller because of Alaskan gas, except in the deregulation case, where there are no shortages, by definition.

The cost of gas will be lower in most regions of the country in 1985 and 1990 if a project is approved, although there are some exceptions. The price difference is usually not large, in the vicinity of 5¢/MMBtu in 1985 and 10¢ in 1990. With incremental pricing, Alaskan gas causes industrial gas prices to rise, while rolled-in pricing causes some higher cost to residential consumers, especially in 1985. Under deregulation, Alaskan gas substantially lowers average costs, by about 10¢ in 1985 and 20-30¢ in 1990.

We recognize that these figures are subject to considerable qualification when their assumptions and methods are examined. Our attempt to draw a few consistent threads from the welter of data is even more uncertain. The raw data must basically stand on its own.

1980

Rolled-In
Incremental
Deregulation

EXHIBIT XI-3

Volume and Price Projections

FEA Demand Region

	1	2	3	4	5	6	7	8	9	10	U.S. Total
ROLLED-IN											
Consumption	.22	.80	1.11	1.32	2.81	5.04	1.03	.65	1.49	.36	14.8
R	3.14	2.90	2.49	2.04	2.04	1.64	1.53	1.55	2.24	3.05	2.13
C	2.57	2.38	2.09	1.61	1.76	1.37	1.20	1.54	1.79	2.54	1.75
I	-	1.79	1.97	1.28	1.48	1.79	2.58	1.88	2.80	1.96	1.85
Shortages	.12	.05	.19	.45	1.33	-	-	-	.39	.16	2.5
INCREMENTAL											
Consumption	.22	.80	1.11	1.32	2.81	5.03	1.03	.65	1.49	.36	14.8
R	3.14	2.68	2.06	1.91	1.83	1.64	1.53	1.55	2.32	3.00	2.00
C	2.57	2.16	1.66	1.47	1.55	1.37	1.21	1.54	1.87	2.50	1.64
I	-	2.61	2.87	1.44	3.82	1.80	2.58	1.88	2.81	2.02	2.03
Shortages	.13	.05	.45	.46	1.38	-	-	-	.37	.16	2.6
DEREGULATION											
Consumption	.32	.72	.96	1.48	3.64	4.60	.82	.51	1.59	.47	15.1
R	4.07	4.12	3.71	3.47	3.41	3.04	3.29	3.23	3.78	4.10	3.53
C	3.50	3.61	3.31	3.03	3.12	2.59	2.95	3.03	3.33	3.60	3.16
I	3.02	3.02	2.95	2.65	2.84	2.34	2.65	2.63	3.01	3.02	2.62
Shortages	-	-	-	-	-	-	-	-	-	-	-

Volumes in trillion cubic feet; prices in 1975 dollars per MMBtu.

1985

Rolled-in Pricing

EXHIBIT XI- 4(a)

Volume and Price Projections

FEA Demand Region

	1	2	3	4	5	6	7	8	9	10	U.S. Total
NO PIPELINE											
Consumption	.33	.80	1.12	1.32	2.42	6.10	1.02	.70	1.88	.30	16.05
Prices - R	3.84	3.50	3.03	2.60	2.52	1.94	1.77	1.77	3.34	3.06	2.62
- C	3.27	2.99	2.64	2.16	2.29	2.16	3.10	2.51	2.89	2.55	2.53
- I	2.78	2.39	2.28	1.96	-	1.91	2.80	2.10	2.29	1.97	2.06
Shortage	.05	.00	.00	.58	1.97	.00	.02	.00	.00	.29	2.90
ARCTIC											
Consumption	.34	.81	1.19	1.45	2.77	6.13	1.03	.69	1.89	.32	16.62
Prices - R	3.83	3.44	3.04	2.67	2.61	1.95	1.73	1.77	3.22	3.07	2.64
- C	3.26	2.92	2.64	2.23	2.32	2.04	3.08	2.51	2.77	2.57	2.54
- I	2.78	2.33	2.28	1.99	2.04	1.79	2.78	2.10	2.37	1.98	2.00
Shortage	.03	.00	.00	.45	1.63	.00	.00	.00	.00	.27	2.38
EL PASO											
Consumption	.34	.81	1.19	1.44	2.69	6.19	1.04	.70	1.89	.82	16.59
Prices - R	3.85	3.46	3.05	2.70	2.63	2.19	2.02	1.78	3.31	3.12	2.73
- C	3.28	2.98	2.66	2.27	2.38	1.82	2.11	2.51	2.96	2.62	2.45
- I	2.80	2.36	2.38	2.02	2.06	1.75	2.78	2.10	2.28	2.04	1.97
Shortage	.04	.00	.00	.46	1.69	.00	.00	.00	.00	.26	2.43
ALCAN											
Consumption	.34	.81	1.12	1.45	2.78	6.13	1.03	.69	1.88	.31	16.63
Prices - R	3.84	3.44	3.04	2.68	2.62	1.96	1.73	1.77	3.23	3.07	2.65
- C	3.27	2.92	2.64	2.24	2.34	2.01	3.05	2.51	2.79	2.57	2.52
- I	2.78	2.33	2.28	1.99	2.06	1.76	2.78	2.10	2.36	1.99	1.98
Shortage	.03	0	.00	.45	1.61	.00	.00	.00	.00	.27	2.36

Volumes in trillion cubic feet; prices in 1975 dollars per MMBtu.

1990

Rolled-In Pricing

EXHIBIT XI-4(b)

Volume and Price Projections

FEA Demand Region

	1	2	3	4	5	6	7	8	9	10	U.S. Total
NO PIPELINE											
Consumption	.38	.78	1.25	1.21	2.42	6.49	.64	.51	1.45	.01	15.16
Prices - R	4.65	4.12	3.47	3.14	3.33	2.61	2.66	2.54	3.36	2.35	3.25
- C	4.08	3.60	3.08	2.71	3.05	3.14	3.37	3.26	2.91	.00	3.12
- I	3.59	3.01	2.76	2.43	2.77	2.89	.00	2.85	3.11	.00	2.81
Shortage	.00	.00	.02	.88	2.25	.22	.43	.22	.55	.62	5.19
ARCTIC											
Consumption	.38	.80	1.28	1.32	2.74	6.54	.67	.52	1.71	.03	16.00
Prices - R	4.57	4.02	3.45	3.14	3.29	2.54	2.57	2.51	3.06	2.75	3.17
- C	3.99	3.50	3.05	2.70	3.01	3.12	3.31	3.25	2.62	.00	3.03
- I	3.51	2.91	2.70	2.41	2.73	2.87	3.01	2.84	2.80	.00	2.82
Shortage	.00	.00	.00	.78	1.96	.18	.41	.21	.38	.61	4.53
EL PASO											
Consumption	.37	.79	1.27	1.29	2.62	6.62	.71	.53	1.71	.03	15.92
Prices - R	4.95	4.05	3.48	3.18	3.34	2.46	2.68	2.51	3.20	3.28	3.21
- C	4.12	3.83	3.08	2.75	3.06	3.12	2.62	3.25	2.76	.00	3.03
- I	3.53	2.94	2.73	2.48	2.78	2.87	3.01	2.84	3.20	.00	2.85
Shortage	.00	.00	.00	.80	2.07	.11	.39	.21	.31	.60	4.52
ALCAN											
Consumption	.38	.83	1.28	1.32	2.75	6.55	.67	.52	1.69	.04	15.99
Prices - R	4.56	3.95	3.45	3.14	3.29	2.54	2.56	2.51	3.07	2.75	3.17
- C	3.99	3.44	3.06	2.70	3.01	3.12	3.31	3.25	2.62	.00	3.03
- I	3.51	2.85	2.70	2.41	2.73	2.87	3.01	2.84	2.81	.00	2.81
Shortage	.00	.00	.00	.78	1.96	.18	.41	.2	.40	.59	4.54

Volumes in trillion cubic feet; prices in 1975 dollars per MMBtu.

1985

Incremental Pricing

EXHIBIT XI- 4(c)

Volume and Price Projections

FEA Demand Region

	1	2	3	4	5	6	7	8	9	10	U.S. Total
NO PIPELINE											
Consumption	.33	.81	1.23	1.31	2.39	6.10	1.02	.70	1.94	0.30	16.11
Prices - R	3.68	3.01	2.50	2.22	2.51	1.94	1.77	1.77	2.67	3.04	2.44
- C	3.11	2.50	2.10	1.78	2.38	2.16	3.10	2.51	2.22	2.54	2.33
- I	3.44	3.71	3.13	2.37	.00	1.91	2.86	2.10	2.96	2.02	2.25
Shortage	.05	.02	.00	.64	1.99	.00	.02	.00	.00	0.29	3.00
ARCTIC											
Consumption	.34	.83	1.23	1.44	2.72	6.13	1.03	.70	1.98	.32	16.72
Prices - R	3.66	2.97	2.50	2.22	2.43	1.95	1.73	1.77	2.55	3.04	2.39
- C	3.09	2.45	2.10	1.78	2.15	2.04	3.08	2.51	2.10	2.54	2.23
- I	3.44	3.61	3.14	2.38	3.45	1.79	2.78	2.10	3.00	2.04	2.23
Shortage	.04	.00	.00	.52	1.71	.00	.00	.00	.00	.27	2.53
EL PASO											
Consumption	.34	.82	1.22	1.40	2.59	6.19	1.04	.69	1.96	.31	16.67
Prices - R	3.69	2.98	2.47	2.25	2.48	2.19	2.02	1.78	2.68	3.06	2.48
- C	3.11	2.47	2.07	1.81	2.20	1.82	2.11	2.45	2.24	2.05	2.18
- I	3.44	3.78	3.21	2.42	3.51	1.75	2.78	2.07	2.87	2.19	2.19
Shortage	.04	.00	.00	.54	1.82	.00	.00	.00	.00	.27	2.59
ALCAN											
Consumption	.34	.83	1.23	1.44	2.74	6.13	1.03	.70	1.98	.31	16.73
Prices - R	3.65	2.97	2.50	2.22	2.44	1.96	1.73	1.77	2.55	3.04	2.40
- C	3.07	2.45	2.10	1.78	2.16	2.04	3.07	2.51	2.10	2.54	2.23
- I	3.44	2.63	3.15	2.40	3.42	1.79	2.78	2.10	3.00	2.06	2.22
Shortage	.04	.00	.00	.52	1.69	.00	.00	.00	.00	.27	2.51

Volumes in trillion cubic feet; prices in 1975 dollars per MMBtu.

EXHIBIT XI-4(d)

Volume and Price Projections

FEA Demand Region

	1	2	3	4	5	6	7	8	9	10	U.S. Total
NO PIPELINE											
Consumption	.38	.81	1.25	1.20	2.42	6.50	.64	.51	1.45	.01	15.2
Prices - R	4.26	3.46	2.99	2.42	3.24	2.61	2.66	2.54	3.18	2.35	3.04
- C	3.69	2.95	2.59	1.99	2.96	3.14	3.37	3.26	2.73	-	2.82
- I	4.46	4.55	3.42	3.27	-	2.89	-	2.85	3.38	-	2.97
Shortage	-	-	.61	1.00	2.30	.23	.43	.22	.58	.62	5.4
ARCTIC											
Consumption	.38	.82	1.31	1.31	2.72	6.54	.67	.52	1.71	.03	16.0
Prices - R	4.22	3.46	2.99	2.42	3.01	2.54	2.57	2.51	2.74	2.75	2.89
- C	3.65	2.95	2.59	1.99	2.72	3.12	3.31	3.25	2.29	-	2.68
- I	4.46	4.14	3.29	3.12	4.83	2.87	3.01	2.85	3.35	-	3.08
Shortage	-	-	.07	.90	2.04	.18	.41	.21	.43	.61	4.8
EL PASO											
Consumption	.38	.82	1.30	1.32	2.59	6.62	.71	.52	1.71	.03	15.9
Prices - R	4.25	3.43	2.95	2.46	3.07	2.46	2.68	2.51	3.11	3.28	2.96
- C	3.67	2.91	2.56	2.03	2.79	3.13	2.64	3.26	2.66	-	2.72
- I	4.46	4.36	3.40	3.13	4.86	2.88	3.01	2.85	3.28	-	3.09
Shortage	-	-	.04	.91	2.15	.11	.38	.21	.31	.60	4.8
ALCAN											
Consumption	.39	.82	1.31	1.32	2.73	6.54	.67	.52	1.70	.03	16.0
Prices - R	4.22	3.46	2.99	2.42	3.01	2.54	2.57	2.53	2.74	2.25	2.89
- C	3.65	2.95	2.59	1.99	2.73	3.12	3.31	3.25	2.30	-	2.68
- I	4.46	4.13	3.29	3.12	4.86	2.87	3.01	2.84	3.38	-	3.09
Shortage	-	-	.05	.90	2.03	.18	.41	.21	.45	.61	4.5

Volumes in trillion cubic feet; prices in 1975 dollars per MMBtu.

EXHIBIT XI- 4(e)

Volume and Price Projections

FEA Demand Region

	1	2	3	4	5	6	7	8	9	10	U.S. Total
NO PIPELINE											
Consumption	.37	.72	1.07	1.73	4.11	5.73	.93	.59	1.74	.54	17.55
Prices - R	4.08	4.13	3.72	3.48	3.42	3.05	3.30	3.23	3.78	4.11	3.53
- C	3.51	3.62	3.32	3.04	3.14	2.59	2.96	3.04	3.33	3.61	3.17
- I	3.03	3.03	2.96	2.66	2.85	2.34	2.66	2.63	3.00	3.03	2.62
Shortage	-	-	-	-	-	-	-	-	-	-	-
ARCTIC											
Consumption	.37	.75	1.10	1.75	4.16	5.78	.94	.60	1.77	.55	17.76
Prices - R	3.96	4.01	3.63	3.39	3.33	2.96	3.20	3.12	3.66	3.99	3.44
- C	3.39	3.50	3.24	2.96	3.05	2.51	2.85	2.93	3.22	3.49	3.07
- I	2.91	2.91	2.88	2.58	2.77	2.24	2.55	2.52	2.89	2.91	2.52
Shortage	-	-	-	-	-	-	-	-	-	-	-
EL PASO											
Consumption	.37	.75	1.10	1.76	4.15	5.78	.94	.60	1.77	.55	17.76
Prices - R	3.96	4.61	3.64	3.39	3.33	2.96	3.20	3.12	3.67	3.99	3.44
- C	3.39	3.50	3.24	2.96	3.05	2.51	2.85	2.93	3.22	3.49	3.07
- I	2.91	2.91	2.88	2.58	2.77	2.25	2.55	2.52	2.89	2.91	2.53
Shortage	-	-	-	-	-	-	-	-	-	-	-
ALCAN											
Consumption	.37	.75	1.09	1.75	4.16	5.78	.94	.60	1.77	.55	17.76
Prices - R	3.96	4.01	3.63	3.39	3.33	2.96	3.20	3.12	3.66	3.99	3.44
- C	3.39	3.50	3.24	2.96	3.05	2.51	2.85	2.93	3.22	3.49	3.07
- I	2.91	2.91	2.88	2.58	2.77	2.25	2.55	2.52	2.89	2.91	2.52
Shortage	-	-	-	-	-	-	-	-	-	-	-

Volumes in trillion cubic feet; prices in 1975 dollars per MMBtu.

EXHIBIT XI- 4(f)

Volume and Price Projections

FEA Demand Region

	1	2	3	4	5	6	7	8	9	10	U.S. Total
NO PIPELINE											
Consumption	3.21	.62	.98	1.66	3.93	5.83	.88	.57	1.53	.50	16.82
Prices - R	5.84	5.89	5.54	5.36	5.35	4.90	5.20	5.20	5.73	6.21	5.42
- C	5.27	5.37	5.14	4.93	5.06	4.44	4.85	5.01	5.28	5.70	5.07
- I	4.78	4.78	4.78	4.55	4.78	4.19	4.55	4.60	4.95	5.12	4.50
Shortage	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
ARCTIC											
Consumption	.38	.64	1.01	1.70	4.01	5.96	.90	.58	1.57	.51	17.21
Prices - R	5.59	5.64	5.29	5.12	5.09	4.65	4.92	4.93	5.45	5.93	5.16
- C	5.02	5.12	4.89	4.68	4.81	4.20	4.57	4.74	5.00	5.42	4.81
- I	4.53	4.53	4.53	4.30	4.53	3.94	4.27	4.33	4.67	4.84	4.24
Shortage	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
EL PASO											
Consumption	.33	.63	1.00	1.69	3.99	5.93	.90	.58	1.56	.51	9.99
Prices - R	5.64	5.68	5.34	5.17	5.14	4.71	5.00	5.01	5.52	6.00	5.21
- C	5.06	5.17	4.94	4.73	4.86	4.25	4.65	4.81	5.08	5.50	4.87
- I	4.58	4.58	4.58	4.35	4.58	4.00	4.35	4.40	4.75	4.92	4.30
Shortage	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
ALCAN											
Consumption	.33	.63	1.01	1.70	4.01	5.96	.90	.58	1.57	.51	17.21
Prices - R	5.57	5.62	5.27	5.10	5.08	4.64	4.93	4.94	5.46	5.94	5.15
- C	5.00	5.11	4.87	4.67	4.80	4.19	4.58	4.75	5.01	5.43	4.80
- I	4.51	4.51	4.51	4.29	4.51	3.94	4.28	4.34	4.68	4.85	4.24
Shortage	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00

Volumes in trillion cubic feet; prices in 1975 dollars per MMBtu.

EXHIBIT XI-5

Field Price Differential Impacts
U. S. Total (Average)
Rolled-In Pricing

	1980	1985 1.00	1985 1.50	1990 1.00	1990 1.50
NO PIPELINE					
Consumption	14.82	16.05		15.16	
Prices - R	2.13	2.62		3.25	
- C	1.75	2.53		3.12	
- I	1.85	2.06		2.81	
Shortage	2.53	2.90		5.19	
ARCTIC					
Consumption	-	16.62	16.58	16.00	15.99
Prices - R	-	2.64	2.69	3.17	3.22
- C	-	2.54	2.55	3.03	3.08
- I	-	2.00	2.01	2.82	2.82
Shortage	-	2.38	2.34	4.53	4.47
EL PASO					
Consumption	-	16.59	16.53	15.92	15.91
Prices - R	-	2.73	2.78	3.21	3.27
- C	-	2.45	2.48	3.03	3.07
- I	-	1.97	1.98	2.85	2.85
Shortage	-	2.43	2.40	4.52	4.45
ALCAN					
Consumption	-	16.63	16.60	15.99	15.99
Prices - R	-	2.65	2.70	3.17	3.22
- C	-	2.52	2.56	3.03	3.08
- I	-	1.98	2.00	2.81	2.83
Shortage	-	2.36	2.31	4.54	4.47

CHAPTER XII

FINANCING AND TARIFFS

A. Introduction

The Alaska Natural Gas Transportation Act of 1976 requires the Commission to evaluate the feasibility of financing the proposed projects. Any of the projects, which may ultimately cost in excess of $10 billion 1/, and which are to be constructed in part under Arctic winter conditions, present a financing challenge greater than any previously considered by this Commission. The uniqueness and complexity of the financing issues exceed those faced by the Alaskan oil pipeline. The hearing record makes clear that the currently proposed gas utility sponsors do not have the financial strength to finance any of the projects to completion. Furthermore, no additional parties have volunteered to provide the necessary financial support.

Judge Litt concluded that in the absence of additional creditworthy parties, ". . . the project financing required here will require either consumer or government backstopping, or both, to guarantee project completion." 2/ We agree fully with this conclusion. However, we are not yet prepared to concede that the backing of additional creditworthy parties is unobtainable.

In particular, during the April 6, 1977 oral argument the State of Alaska indicated that it ". . . is searching for a way to participate meaningfully in the financing of the El Paso project . . .", and that if the El Paso project is ruled out ". . . the State would then seriously consider whether to

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1/ As discussed herein, the capital cost estimates for the projects range between 6 and 8.5 billion 1975 dollars. After allowing for inflation and cost overrun contingencies, the nominal dollar capital cost may exceed 10 billion.

2/ I.D. 365.

assist the financing of the Alcan Project." 3/ Further, the Atlantic Richfield Company - a major Alaskan gas producer - indicates an open mind regarding gas transportation system investments. 4/ The Department of the Treasury continues to suggest the possibility of participation by industrial gas consumers. 5/ In addition, we would prefer to see more gas pipeline and distribution companies involved in the purchase of Alaskan gas and in the transportation system financing. 6/ Our recommendation regarding the distribution of Alaskan gas discussed herein should provide the basis for participation by an increased number of such companies.

As discussed in detail in the various submissions by the Department of the Treasury 7/ and the Federal Power Commission Staff, 8/ the required supplemental financial support could be provided by a large consortium of potential direct beneficiaries of the project. Parties having the capacity to participate in the financing include the oil companies owning gas reserves, the State of Alaska, additional gas utilities, and other corporate investors. If successful, a traditional financing approach involving these parties would minimize consumer investment guarantees and avoid involving general taxpayers. To the extent possible, we believe consumers 9/ should retain their traditional role of paying for energy as it is consumed, rather than bearing the risks of a new enterprise. The Treasury Department has voiced similar opinions on risk bearing by general taxpayers, who

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3/ 257/45,140-141.

4/ Brief on Exceptions, March 1, 1977, pp. 8-12.

5/ Brief on Exceptions, p. 9.

6/ Also see Chapter X for reasons why a broad distribution of the gas would be desirable from a competition standpoint.

7/ 250/43,608; and ST-58, pp. I-14.

8/ ST-14, p. 14.

9/ We use the term consumers to mean end-use gas customers.

are less direct beneficiaries of the project than either the previously mentioned potential sponsors or gas consumers.

With the currently expressed policy of the Treasury in mind, our finance and tariff recommendations initially focus on several proposals which we hope will provide adequate incentives to these companies and the State of Alaska to make the necessary capital investments while bearing acceptable risks. Since some of our proposals were not fully considered in the record, a special proceeding to perfect the details may be needed in the near future. Of course, the success of this private financing approach is dependent on favorable decisions by the indicated parties to provide financial support for the project.

We have also considered an alternative financing approach which shifts more risk to consumers by having them guarantee repayment of the project's debt financing. If such consumer guarantees are required, we believe that special care must be taken to insure that consumers' financial interests are protected and that the rates of return on invested capital reflect the shift of risk bearing from capital suppliers to consumers. While we believe private parties should be allowed an adequate profit potential for bearing most of the project's considerable risks, we believe it would be unfair to place the bulk of the risk on gas consumers while other parties receive substantially all of the net economic benefits.

Given the size and complexity of any of the projects, any financing proposals will be controversial. If general taxpayer guarantees are to be avoided, we believe that innovative approaches are required in this unique project financing situation. We have been unable to answer all the financing questions, and much work will be required over the next several months before a successful financing can be designed. We hope that other interested parties including the potential project sponsors, financial community, various Federal and State regulatory bodies, and Governments of the

United States and Canada will recognize the importance and uniqueness of the project and work together to resolve the remaining issues.

We have not recommended Federal financial assistance for an Alaskan gas transportation system. In our opinion, 10/ Federal backstopping is a default option to be employed only if it is determined that the social benefits of a transportation system are overriding and private parties are unwilling to undertake the project alone at a reasonable cost. As indicated by the large positive net national economic benefits of all three systems (see Chapter IV), the social benefits are undoubtedly adequate to warrant the construction and operation of any of the systems. The imposition of taxes, the likelihood of cost overruns, the possibility of project noncompletion or extended service interruption, and the risk-averse nature of potential investors have raised questions regarding the achievement of a private financing. We believe, however, that the private benefits are substantial and the risks bearable under the financing method we outline herein. For these reasons, and the position taken by the Treasury Department, we have not believed it appropriate to recommend a financing plan contingent on Federal guarantees.

B. Financial and Economic Risks

A successful financing will have to attract both equity and debt capital. The usual requirement for attracting equity financing is to provide investors with the prospect for an adequate return to compensate them for the level of risk incurred. In this case, certain sponsoring utilities hope to receive such a large percentage of available Alaskan gas supplies that an equity investment of proportional size is thought to exceed an amount for which they can bear normal equity risks considering their corporate capital structure. This financing problem is considered in more detail under our recommendations regarding the need for a broader distribution of Alaskan gas in the various domestic markets.

10/ Commissioner Smith believes a stronger case for Federal financial participation was made.

Potential project lenders can also be expected to be concerned about the project's economics and risks. However, the record makes abundantly clear that the credit backing for the debt financing will be the crucial determinant of whether adequate amounts of financing will be made available. Institutional lenders require debt guarantees which offer them good prospects for recovering their loans with interest even if the project fails completely. This basic requirement for a successful financing is present because, as Judge Litt states, "[t]he proposed gas transmission pipeline in this case would have little salvage value and is poor collateral either prior to, or after completion. It thus represents little security that a lender would recoup on his investment, principal and interest, if it were necessary to exercise the lender's prerogative to step in to protect his position following a default." (I.D. 361). The current gas utility sponsors cannot provide the required credit backing alone. Other parties to guarantee debt repayment must be found to cover the contingency of project failure.

1. Risk of Project Being Uneconomic

While the evidence indicates that Alaskan gas can be delivered at a competitive price, 11/ a principal risk is that due to cost overruns, declines in the real level of world energy prices, smaller than anticipated levels of gas production or shipment, or some combination of these factors, the delivered cost of gas might exceed its economic value to consumers. While we firmly believe this marketability risk is small, gas consumers may have to bear a portion of that risk if the project is to attract private financing. Equity investors and gas producers should also bear some of this risk.

11/ See the Interior Department's Report to Congress entitled, Alaskan Natural Gas Transportation Systems (E.P. 231, pp. 46-62, and 112), the testimony of Arctic Gas Witness Schantz (174/28,658), the Initial Decision (pp. 346-350, 367, 368), and Chapter IV of this recommendation for a discussion of this issue.

Such project sponsor risk bearing should be an integral part of any sound financing plan, since it provides them a direct incentive for efficiency in construction and operation of the project. Both major alternative financing approaches discussed herein have been constructed to create incentives for efficiency. The plans further provide substantial protection for the consumer against paying a higher than market value for Alaskan gas.

As discussed in Chapter IV, in terms of lowest transportation cost of service, Arctic Gas ranks first, Alcan second, and El Paso third. 12/ All three proposals face equal risks of a decline in the real levels of world energy prices and smaller than anticipated Alaskan gas production. 13/ Thus, the ranking of the three proposals with regard to the risk of an uneconomic delivered cost of gas is derived from a weighing of the risk of cost overruns and/or schedule delays with the currently estimated cost of service differentials between the various projects. When this test is applied, El Paso has the lowest risk of cost overruns in excess of current estimates, Arctic Gas has the highest risk due to potential problems in winter Arctic construction, and Alcan is somewhere in between with a principal risk being one of cost estimate increases as the specific details of their most recent proposal are completed. On balance, the Arctic Gas and Alcan proposals probably will continue to have some advantage over the El Paso proposal on a cost of service comparison. However, this advantage may be smaller than current estimates indicate due to Arctic Gas and Alcan's greater risk of cost increases over current estimates. For the purposes of this chapter, such contingent cost of service differentials - while being an important consideration - would not seem likely to be a controlling factor.

12/ This comparison is based on most recent cost of service filings by applicants.

13/ It might be argued that, for Arctic Gas, the hope of larger than anticipated Mackenzie Delta gas supplies partially offsets the risk of smaller than anticipated Alaskan gas production. However, as discussed in Chapter III, we do not find this event to be likely.

2. Risk of Noncompletion

A second risk of the project is that because of extreme cost overruns, technological or physical problems, or *force majeure* events, the project may not be completed. While the record supports the conclusion that the risk of noncompletion is slight, the possibility cannot be ignored. 14/ Institutional lenders will undoubtedly require some creditworthy party to agree to finance the project to completion or repay the outstanding debt in the event of noncompletion. If private investors bear the noncompletion risk, we are willing to rely on their judgment regarding how best to respond to this remote contingency. However, if gas consumers are required to bear a major portion of the risk of noncompletion, additional measures will be needed to protect their interests. The financing alternatives we explore include measures designed to minimize the amount of consumer's liability in the event of project failure.

3. Risk of Service Interruptions

A third risk the project faces is that inadequate gas production, accident, natural disaster, or *force majeure* event, could substantially reduce or cause lengthy interruption of gas deliveries to consumers. Service interruption could create significant economic disruptions if Alaskan gas were to comprise a large percentage of a particular system's total gas supply. If in addition to bearing the economic dislocations caused by service interruption, gas consumers are also required to bear the risk of repaying debt financing in such event, then additional measures will be needed to protect their financial interest. We therefore believe that producer

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14/ Even extensive cost overruns are not likely to halt any of the projects, since only the remaining costs would be relevant to the decision to stop the project; the already-incurred expenses would be sunk.

throughput agreements 15/ would be desirable and a reasonably broad distribution of Alaskan gas in lower 48 states' markets would be appropriate to moderate the potential financial and economic impacts of service interruptions on consumers.

While we view the probability of extended service interruption to be slight under each proposed system, El Paso would appear to have a higher risk due to its more complicated delivery system and greater seismic problems. 16/

We accept the proposition that in total the economic and financial risks associated with building and operating a project of this magnitude are greater than in any gas utility project which this Commission has ever certificated. Recognizing this higher level of risk, we will consider herein gas pricing and rate of return on equity arrangements which we believe would offer private parties an incentive to both supply the necessary capital and bear the risks associated with the project.

C. Summary of Principal Investment Guarantee Proposals

A central financing issue which received extensive consideration on the hearing record is how to make the proposed projects sufficiently creditworthy to attract the necessary debt capital. With neither the gas producers or - at that time - the State of Alaska indicating an active interest in participating in the financing, the record discussion turned primarily to proposals for consumer or general taxpayer debt guarantees. A second issue receiving considerable attention was whether equity investors should also be allowed to recover their investment in the case of project failure. As background for discussion of our alternative

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15/ A throughput agreement would contain a gas producer commitment to make available to gas shippers a minimum volume of gas for a minimum period of time or alternatively make a portion of debt service payments.

16/ See Chapter VII for a discussion of comparative system reliability.

financing proposals, a summary of the positions taken by the three applicants, Federal Power Commission Staff, State Utility Commissions, Treasury Department, and Judge Litt is given below.

1. El Paso

After recognizing that a successful financing for any of the proposed projects would require guarantees of recovery of - at least - debt service payments in the event of extended service interruption or project noncompletion, and favoring all-events cost of service tariffs 17/ and noncompletion agreements which would commit consumers to making such payments, El Paso took the position that its project ". . . can be financed under present conditions without federal financial assistance." 18/ The basis for El Paso's position is summarized on pages 371-377 of its Brief on Exceptions as follows:

17/ An all-events cost of service tariff would charge the shippers for all the period operating and capital costs regardless of the volume of throughput.

18/ Brief on Exceptions, p. 370.

"1. The Natural Gas Act and court decisions thereunder invest the Commission with a sufficient body of power to exercise plenary control over the initial sale, transportation and resale of Alaskan natural gas.

2. The Constitution of the United States and principles emanating therefrom, provide the means for implementing this power so as to effect desired results at the distribution and consumer levels.

3. If the overall national public interest dictates that the ultimate credit support for the financing of an Alaskan gas delivery system should be the gas consumer, the Commission should proceed to arrange and integrate its decision-making to accomplish that end.

4. The financeability of the project depends upon assuring the investors in the project that they will not suffer the loss of their investments if the project should crater. This can be accomplished by approved tariff clauses in the tariffs of transmission company shippers which permit them to pass through to their customers as a service charge the cost of investment recovery should the project be abandoned or become inoperative leaving unrecovered costs.

5. The integrated ordering mechanism suggested is that the Commission approve an all-events, cost-of-service tariff for the project company; that it approve gas sales to interstate transmission companies under its jurisdiction; that it approve rolled-in pricing so that the cost of Alaskan gas will be carried as a subsumed cost factor in the rate for flowing gas being sold for resale in interstate commerce to local distribution companies, and that it approve a modified purchased gas adjustment clause for the tariff of each transmission company acquiring Alaskan gas which would permit the obligations to the project company, in case of either abandonment or inoperability to be flowed through to its distribution company customers. 19/ [Footnote added.]

6. The obligations referred to in 5, *supra*, would include the charges authorized under the approved all-events tariff and its service agreement and a pre-completion contractual obligation by the proposed shipper to make payment of a pro rata share of investment recovery if the project is not completed.

7. If the Commission finds that the project is in the public interest; that it cannot be financed under existing law without assuring investors that they may have investment recovery in all events;

19/ Hereafter, such automatic flow through of costs is referred to as "tracking".

that tracking mechanisms are required in the tariffs of the affected jurisdictional companies to provide the means of assuring that the consuming public will pay the charges necessary to make investment recovery, and that it should approve such tariff mechanisms to induce the necessary financing, the Commission will be estopped from changing those tariff provisions in a way which would adversely affect the investor who relied upon the Commission's prior tariff provision approvals.

8. The charges for natural gas transportation service, which includes by comprehension the tariff which authorizes the charges, are by the terms of the Natural Gas Act conclusively presumed to be fair and reasonable and may not be attacked in any other forum. Montana-Dakota Utilities Co. v. Northwestern Public Service Co., 341 U.S. 246 (1951).

9. By virtue of the supremacy clause of the Constitution of the United States and the doctrine of federal preemption, the states, and by inclusion their public regulatory bodies, are without authority to disallow the charges authorized by a valid tariff.

10. Since the refusal of a state public utility commission to allow a distribution company subject to its jurisdiction to recover in its rates lawful charges collectible from it for gas service from an FPC regulated transmission company, is confiscatory and therefore a violation of the due process clause of the Fourteenth Amendment to the Constitution, West Ohio Gas Co. v. Public Utilities Commission of Ohio, 294 U.S. 63 (1935), the costs of investment recovery must be allowed at the local level."

The consequence of these points is that this Commission has within its authority under current law -- without additional legislation -- to provide the regulatory framework for investment recovery and thereby assure financeability in the private sector of a project which is solely subject to the jurisdiction of the Commission." (footnotes deleted)

The basic criticisms of the El Paso proposal have been that it does not account adequately for possible regulatory lag in the passthrough of costs to consumers by state regulatory commissions, 20/ and that there is

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20/ See Brief of Alaskan Arctic Gas Pipeline Company, Pacific Gas Transmission Company, Northern Border Pipeline Company, on Completion and Interruption Assurances Required for Financing Gas Transportation Systems from Arctic Areas to the Lower United States; June 29,1976, pp.21-29. In this brief, Arctic Gas agrees with El Paso that under an all-events tariff or noncompletion agreement - approved by the Federal Power Commission - that customers of natural gas companies paying charges pursuant to such tariff provisions "... for the purchase of flowing gas sold to them under an existing service agreement, must be permitted to recover those costs as a just and reasonable expense item by their own state regulatory agencies..." (p.21). However, Arctic also identifies the risk of regulatory lag at the State level, by stating "...there is no way by which the Commission can require the States to permit a direct flow through concurrently of such charges to consumers able to pay them." (p.24).

not sufficient support for its assertion that the Federal Power Commission would be required to maintain tracking tariffs in place under principles of estoppel. 21/ El Paso responds to these criticisms as follows: 22/

> ". . . As to the first [criticism] one would not assume that a local distribution company having notice of an FPC-approved tariff which would permit tracking of costs arising from non-completion or interruption undertakings, would wait until non-completion or interruption had occurred to seek to modify its own tariffs so as to acquire the ability to track immediately any charges required by a Commission-approved tariff to be paid to the interstate transmission company by the distribution company. To the extent that a state would not permit such a tracking device, a judicial proceeding would certainly be a satisfactory method to ascertain whether the purpose of the denial was to prevent implementation of a federal regulation. It would not seem difficult to frame an appropriate issue for a Declaratory Judgment action. In any event, it is not to be assumed that state regulatory commissions would deliberately delay the processing of rate cases to accomplish this purpose. The courts do remain open to address such grievances.

21/ Ibid.

22/ Brief on Exceptions, p. 379.

To paraphrase Mr. Justice Holmes in Panhandle Oil Co. v. Mississippi ex rel. Knox, 277 U.S. 218,223 (1928): "The power to [delay] is not the power to destroy while this court sits." 23/

With respect to the criticism that Federal regulatory authorities might modify the approved tracking tariffs due to "changed circumstances," El Paso responds as follows: 24/

> " . . .What we have postulated is that the increased charges which interstate transmission companies would be required to bear resulting from non-completion or interruption undertakings are related to the costs which have been accumulated by the project and which have already been found under the Commission's proposed auditing procedure to be fair and reasonable. Under

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23/ Further there would seem to be other ways to solve the cash flow problems created by potential regulatory lag at the State level. A broad distribution of Alaskan gas across domestic markets would minimize the problem if a few states were slow in allowing cost passthrough. In addition, a creditworthy party (e.g. the State of Alaska, or the gas producers) could provide guarantees for a short term line of credit adequate to cover the project's cash flow needs for a certain period of time (for example, six months). Alternatively, a consumer surcharge could be used to build up a cash reserve fund adequate to cover this contingency. With a little imagination and cooperation by the interested parties, we believe the potential problem of State regulatory lag in cost passthrough can be solved.

24/ Brief on Exceptions, 384-385.

our proposal there is no abandonment of jurisdiction to a third party. 25 / The charges which are tracked by the transmission companies are the very ones which the Commission anticipated when it first approved the tariff. There can be no surprises to this Commission if it has had the opportunity to frame the rules. When it shares its responsibility with another regulatory body -- as it did in the PGT case -- it may indeed be surprised if that other body acts in an independent manner." [Footnote added.]

El Paso further raises two alleged problems with respect to either Arctic Gas or Alcan using similar tracking provisions in their tariff structure to provide credit backing for their projects. First, it is asserted that "The Commission cannot authorize the flow-through automatically of NEB (National Energy Board) approved transportation charges." 26/ However, the Commission does not agree that it is so constrained under the Natural Gas act, or as a result of the Pacific Gas Transmission case.

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25 / In this instance, El Paso is referring to the National Energy Board which has the authority to determine what costs the Canadian companies integral to the Arctic Gas and Alcan projects would be allowed to charge U.S. shippers.

26 / Brief on Exceptions, 385. El Paso cites the recent Pacific Gas Transmission case where the Commission found that - due to sharp increases in the price of Canadian gas imports - a significant change of circumstances had occurred which justified a modification of an earlier approved cost of service tariff.

Second, El Paso asserts that for the portion of Arctic Gas or Alcan's costs which are allocated to the transport of Canadian gas for Canadian use:

> ". . . There is no requirement imposed on provincial regulatory bodies to permit the flow-through of a charge authorized under a NEB tariff. Since there is no doctrine of federal supremacy or preemption or due process, cases such as West Ohio Company v. Public Utilities Commission of Ohio, 294 U.S. 63 (1935) are simply not applicable in Canada.
>
> In short, automatic tracking will not work for Canadian distribution companies. 27/ It is the inability of the Arctic Gas system to make use of the El Paso proposal which prompts the opposition to it." 28/ [Footnotes added.]

27/ To our knowledge, neither Arctic Gas or Alcan has refuted this assertion. Of course, with the Alcan 48" proposal to transport only Alaskan gas to U.S. markets, the problem would not arise unless Mackenzie Delta or other Canadian gas was subsequently carried by that system.

28/ Brief on Exceptions, 386.

2. Alcan

In the most recent submissions regarding its 48-in alternative proposal to transport Alaskan gas to U. S. markets, Alcan has taken the following position on consumer or taxpayer investment guarantees. 29/

> "Shippers must have the ability to "track" such costs through to their customers much in the same manner that purchased gas costs are currently handled under purchased gas adjustment clauses. Alcan's financing plan places primary reliance upon the tariff mechanism and complete tracking of the resultant charges. If such tracking is not obtainable in in a form satisfactory to lenders, Alcan believes that some kind of contingent financial support from the U. S. government or other creditworthy parties is necessary.
>
> The credit underpinnings of the Alcan Pipeline Project being based upon financial access to a large number of consumers of natural gas, require that the revenue streams provided by the tariffs or contractual agreements continue under all circumstances, including the situation where no transportation service is provided because of noncompletion or extended interruption of service. Investors will not invest in the project unless shippers have an unconditional obligation to continue to make the monthly payments. The issue of tracking assumes such importance because the shippers are otherwise unable to make payments during extended periods when no service is being provided. It is only in the absence of reliable tracking during periods of no service that Alcan suggests supplementary financial support from the U. S. government or other creditworthy parties. Alcan believes that it is proper that the final decision as to whether the ultimate financial

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29/ Alcan 48" Proposal, March 8, 1977.

support for the system be provided by the natural gas consuming public in the form of tracking or by the tax-paying public in the form of guarantee or insurance programs, be made in the regulatory and political arenas.

Alcan does not feel that tariff mechanisms are adequate alternatives to economically and technically viable projects. Alcan believes that the economics of its project are sound, and that it will be able to convince investors of this important fact. It believes that adequate gas reserves are in place to support its project, that the technical aspects of its proposal, including the routing, are superior to those of Arctic Gas or El Paso and that lenders will take strong comfort from these features, including its use of existing utility corridors. Alcan's belief that lenders will receive assurance from its technology is a major reason why Alcan does not categorically state that U. S. government guarantees are absolute necessities, as does Arctic Gas . . .

Alcan believes that the following regulatory steps which will assist in the financing, some of which will require legislation, should be taken:

1) Order that Alaska gas be priced to the distribution companies on a rolled-in basis.

2) Authorize full cost of service tariffs for the project companies, thereby permitting the transportation companies to recover from the shippers of Alaska gas all prudently incurred costs.

3) Provide all regulatory approvals necessary to permit shippers to provide for tracking all costs incurred pursuant to the transportation company's cost of service tariff or to the contractual agreements entered into in lieu of such tariffs.

4) Allow regulated natural gas companies to include their investments in a project transportation company in their rate bases at least until the project becomes operational.

5) Provide a method to insure that local regulatory authorities cannot impede the distribution company's ability to recover, on a timely basis, all project costs from the ultimate consumer.

6) Assure that required regulatory approvals will remain in effect during the life of the project."

3. Arctic Gas

Arctic Gas also supports the use of rolled-in pricing, a cost of service tariff with an "almost all-events" feature, and automatic tracking of costs through to consumers. 30/ However, as the following summary statement on the need for government financial support indicates, Arctic Gas is much less optimistic about achieving a completely private financing:

> ". . . the severe practical problems encountered in obtaining assured regulatory devices so buttressing the credit of those parties giving such assurances as are required to satisfy lenders, equity investors and shippers, are such that complete success is uncertain, and in any event so time consuming, that the more practical and expeditious means of financing within a reasonable time frame may be to secure strictly limited government backstopping against the remote contingencies of non-completion and permanent interruption." 31/

30/ Brief of the Arctic Gas Project Relative To Financing Brief, 12/13/76, p. 4.

31/ Arctic Gas Initial Financing Brief, p. 3.

Arctic bases its position on what it considers to be purely practical grounds since . . .

> "it is by no means certain that any regulatory devices, in addition to those requested by Arctic Gas, could be adopted by regulatory agencies and accepted by shippers which would satisfy the security requirements of lenders, and in any event the effort to do so would not be assured of success and would appear to be unduly time-consuming." 32/

Arctic contends that ". . . there is also a very real public interest question involved: should government backstopping against remote contingencies be provided, not merely because it is the more practical (and probably will be found in time to be the only feasible) solution to the completion and interruption assurance problem, but also because the general public (through the government) should in all equity assume the risks of remote contingencies, rather than the initial consumer recipients of the gas." 33/ Nevertheless, Arctic indicates that ". . . if government backstopping does not become available, Arctic Gas certainly will attempt to finance on the basis authorized, and the superiority of its basic project, as well as the strength of its sponsorship, will provide an advantage." 34/

32/ Brief of The Arctic Gas Project Relative To Financing Brief, p. 5

33/ *Ibid.*

34/ *Id.* at 6.

Regarding the scope of government financial support, Arctic's position is as follows:

"First, Arctic Gas believes legislation will be required if government financial support is to be provided to any of the three proposed projects. That legislation should authorize negotiation, between the successful applicant and a designated government official, of the specific terms of any support provided.

Second, the kind of government support Arctic Gas envisages is not direct government financing, or direct guarantees of Project companies' security issues originally committed for by investors. What is envisaged is a "lender of last resort" role by government to provide the completion assurance needed by lenders, whereby the government would undertake to provide, either by loans or by guarantees of loans, the funds needed to assure completion of the project, if the funds required therefor (over and above those originally committed) could not be obtained from private investors, or in the alternative, to abort the project if it was determined the cost of completion would be uneconomic, and pay off all indebtedness incurred to the point of project abortion. In the operations interruption area, it is envisaged that government would act as an "insurer of last resort," undertaking to pay the tariff charges of the Project companies if prolonged outages of service were experienced, after exhaustion of any private business interruption insurance coverage obtained, or in the alternative to pay off all indebtedness then outstanding and discontinue the Project. The precise details of providing such support must await negotiation between the designated government officer and the successful applicant.

Third, any such U. S. government support for Arctic Gas would apply to all portions of the Project located wholly within the U. S., and to such part of the Canadian facilities as represented an equitable U. S. share of responsibility therefor. Determination of that equitable share must await negotiations between each of the two governments and Arctic Gas, with the possibility that some direct negotiations between the two governments themselves will be found desirable." 35/

Federal Power Commission Staff and States

Federal Power Commission Staff makes a clear distinction between consumer investment guarantees prior to and after project operations begin. Once the project goes into operation, Staff would propose a cost of service tariff under which ". . . debt service and operating expenses of the project are guaranteed and, in essence, constitutes a minimum bill. As such shippers would then be entitled to place the cost of that 'minimum bill' into the demand component of their rates, which will guarantee recoupment of those costs under their rate structure . . ." 36/ This concept also seems to have support among some state utility commissions, although hesitation still persists regarding truly long-term service interruptions (i.e., 5 to 10 years). 37/

On the other hand, Commission Staff clearly favors general taxpayer noncompletion guarantees for debt financing over similar guarantees by gas consumers. 38/ While the State Utility Commissions generally concur in this position, 39/ the following excerpt from the State of California's Brief on Exceptions indicates that if other project beneficiaries share some of the risks, California might support additional consumer risk bearing.

35/ Id. at 13-14.

36/ Answering Tariff Brief on Commission Staff, 12/1/76, pp. 24-25.

37/ See oral argument by State of New York, T. 257/45,100.

38/ See Commission Staff Brief on Financing Issues, 12/15/76, p. 13.

39/ See oral arguments of State of New York (T.257/45,101), and State of California (T. 257/45, 128).

"The findings in the Initial Decision with repsect to the financing of an Alaskan natural gas transportation system and the legislative or tariff provisions necessary to implement such financing are premised to a large extent on the continued refusal of either the North Slope producers or the State of Alaska to share in the risks of financing an Alaska natural gas transportation system. The CPUC continues to oppose payment of debt service by the consumer in the event of project noncompletion, and it continues to oppose any form of "consumer surcharge" 40/ or CWIP to finance the shippers' equity investments in an Alaska natural gas transportation system, while at the same time the North Slope producers, the State of Alaska and the Federal government refuse to share in the risks of constructing such a system.

In this respect, the CPUC takes issue with the Presiding Law Judge's implications that California is not willing to assume any risks. On the contrary, the CPUC has stated its willingness to have California's gas consumers assume risks which they have never before assumed, namely the payment of debt service and a _pro rata_ return on equity in the event of sustained or permanent outage, once the project is operational. However, the CPUC is unwilling to extend the risk which California gas consumers should bear for the proposed project, absent a showing by other beneficiaries, such as the North Slope producers, the State of Alaska and the general taxpayer, of their willingness to share some of the risks of transporting North Slope gas to the lower 48 states.

Based on the foregoing statements _and under the present circumstances_, the CPUC _opposes_ the Presiding Law Judge's recommendation that the gas consumers guarantee the payment of debt service in case of non-

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40/ The State of New York takes a different position in that it would support some type of surcharge if favorable tax rulings can be secured. T. 257/45,103. See further discussion on this issue _infra_, pp. XII 56-58.

completion of the project; supports the recommendation that the equity holders receive no return of or return on equity in case of noncompletion of the project and receive a *pro rata* reduction of the return on equity in the event of an sustained or permanent outage after completion of the project; urges the assumption of debt service in the event of noncompletion of the project by some entity other than the consumer--whether that entity be the North Slope producers, the State of Alaska or the Federal government; opposes any form of CWIP or other consumer prepayment or surcharge to shipper companies to cover the financing costs of their equity investments in an Alaska natural gas transportation system." 41/ [Footnotes Deleted]

Treasury Department

The most recent statement of the Treasury Department's support for a private financing came in the form of a letter to the Chairman of the Federal Power Commission at the time of the April 8, 1977, oral arguments which, in part, read as follows:

". . . Treasury does not favor any particular applicant. The Department's interest is to see that the project ultimately selected is structured and operated under terms and conditions that will enable it to be financed without Federal financial assistance.

The Department continues to believe that it is unwarranted and premature to conclude at this time that any Federal financial assistance or any particular type of Federal assistance is needed for this project. There are a number of decisions yet to be taken by the

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41/ Brief On Exceptions of The People of The State of California And The Public Utilities Commission of The State of California, 2/28/77; pp. 4-6.

private parties and the various regulatory bodies involved with the project which could determine whether the project can ultimately be financed in the private markets. For example, gas sales contracts have not been signed and the ultimate project sponsors and purchasers of the gas are not yet known; the State of Alaska has not yet decided on the gas flow which will maximize the development of the Prudhoe Bay reservoir; the extent of consumer risk bearing has not yet been determined; and the producers have not reached a decision as to whether they will help bear any of the financial risks of the project. Until these issues are resolved, it is premature to reach any definitive conclusion as to the ultimate need for Federal financial assistance.

The Treasury Department continues to believe, that with appropriate regulatory decisions and equitable sharing of financial risks by <u>all</u> of the project's direct beneficiaries, it may well be feasible to finance the project without any new types of Federal financial assistance. Therefore, rather than make a premature judgement on the need for Federal financial assistance, the Commission is urged to resolve as many of the outstanding financing issues as possible in order to lay the foundation for the selected project to approach the private capital markets to secure financing.

For example, the Commission in its recommendation to the President should focus on (1) assuring that the designated system is sponsored by the strongest possible consortium of companies; (2) approving a tariff whose terms and conditions will help assure lenders that debt will be repaid in all circumstances once the project is completed and operational; and (3) recommending realistic methods, without Federal financial assistance, to help assure lenders that debt will be repaid in the remote event of noncompletion of the project.

By making specific recommendations on these as well as other financing issues, the Commission will greatly facilitate the President's determination, pursuant to section 7(6)(c) of the Alaska Gas Transportation Act of 1976, whether it can be reasonably anticipated that the system he recommends can be financed without Federal financial assistance. . ."

Initial Decision

On the issue of shifting or sharing risks, Judge Litt concluded that:

1. The natural gas consumer is one of the principal beneficiaries of attaching this new source of natural gas to the existing natural gas transmission pipeline network.

2. Consumer participation in guarantees on capital costs should occur, but only for the debt service represented by all-events tariff. 42/

3. The equity holder should accept the usual risk of equity investment. Compensation for that risk, given the circumstances here, should be at the higher levels of return currently allowed by the Commission. In order to insure that the equity investor is in fact exposed to the risk, it may be necessary to modify

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42/ The Initial Decision also found, ". . .that regulatory provisions necessary to provide consumer guarantees of the project would require Federal legislation, just as surely as legislation would be required for Federal monetary guarantees. The legislation would lock tracking into place and prevent state interference with the regulatory scheme approved by the Federal Power Commission." I.D. 381.

the cost-of-service tariff of the transporter to assure that collection of the depreciation charge does not recover equity capital during periods of prolonged continuous outage. A "grace Period," not to exceed 30 days, for example, would be appropriate, after which the opportunity to recover equity capital would not recur until such time as service resumed. To the extent that lost service could be made up by excess deliveries within 1 year, shippers should pay additional charges to reimburse the disallowed equity recovery. Immediate notification to the Commission of any interruption exceeding 1 day's duration should be required.

4. With the above arrangements in place, the Federal government should entertain an insurance or completion guarantee arrangement to facilitate raising project debt capital at a more reasonable cost and thereby reducing the cost of gas to the consumer." 43/

D. New York Public Service Commission Proposal to Deregulate All Aspects of The Project

In its comments on the sponsor's finance and tariff proposals, the Public Service Commission of the State of New York made the following proposal to undertake a market test of the viability of an Alaskan natural gas transportation system.

> "If despite the costs, transportation and sale of Alaskan gas in markets in the lower 48 states is economically sound on its own terms, gas consumers can be expected to pay an appropriate price for the gas, including a return on industry 44/ investment commensurate with the risk. We recognize however,

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43/ I.D. 392.

44/ In this context, the "industry" is considered to include gas producers, shippers, and distributors.

that one inhibition on the industry's willingness to assume the risks of a costly venture which might nevertheless turn out to be economically justified could be the existing regulatory restrictions on the achievable return on investment plus other real or imagined governmental limitations on their participation in a joint venture of this magnitude. If these fears are in fact the primary restraints on appropriate industry participation, then we submit rather than imposing the risks of the venture upon existing gas consumers who might not even benefit from a successful project, it would be appropriate to consider legislation which would, on an incremental basis, free the sale and transportation of Alaskan gas within the United States from wellhead to burner tip from economic regulation and other governmental restraints, and permits the producers, transporters, domestic pipelines and distributors to agree among themselves how best to allocate costs, risks and revenues in a manner which would result in an alternate sales price to the end consumer of Alaskan gas as a separate fuel in competition with other gas supplies or available fuel alternatives. 45/"

The New York proposal has three prominent characteristics. First, since gas consumers would be buying Alaskan gas on an incremental basis 46/ and since consumers would be expected to do so only when its price did not exceed the price of alternative energy sources, gas consumers would bear none of the risks of the project being uneconomic or not providing service at the level anticipated. Second, market forces would tend to establish a field price for Alaskan gas equal to the city-gate market value of the gas minus the transportation

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45/ Comments of the Public Service Commission of the State of New York on Financial and Tariff Briefs, July 13, 1976, pp. 3-4.

46/ Presumably the transportation system would be built prior to any contract for sale.

cost to the lower 48 states. Third, between them equity investors in the pipeline and gas producers would make profits (or suffer losses) equal to the market value of the gas minus the cost of producing and transporting it to market.

Unfortunately, the feasibility of such an approach is uncertain. In particular, the consensus of the expert financial testimony is that the project cannot be financed if incremental pricing is adopted due to risks regarding the marketability of the gas.

Nevertheless, we believe that the New York proposal has considerable theoretical merit. In developing the private risk-bearing approach to financing which we believe to be more practical, we adopted some of the characteristics of the New York proposal.

E. Incremental vs. Rolled-In Pricing

The pricing of Alaskan gas, both in the field and in various transactions all the way to the burner-tip, has important implications for the financing of a gas transportation system. Judge Litt recommended the use of rolled-in pricing for sales of Alaskan gas by shippers to gas distribution companies because of its greater administrative feasibility and because of financing problems if incremental pricing is imposed on the project. 47/ Furthermore, incremental pricing requires support by state public service commissions, if it is to be carried to the burner-tip.

Incremental pricing creates a problem in finding potential backers for the project because this pricing system raises the risk that Alaskan gas could not be sold, in competition with alternative energy supplies, at a price high enough to cover its costs. 48/ Rolled-in pricing, where the cost of Alaskan gas is averaged with other gas supplies, avoids this problem since the gas will almost certainly be marketable.

Since incremental pricing does provide a market test of the economic attractiveness of Alaskan gas, its use should only be ruled out where proof of such economic viability is unnecessary. It is our judgment, based on the record, that Alaskan gas most likely could be sold competitively on an incremental pricing basis. However, the net national economic benefit of the project is positive and large. 49/ Since Alaskan natural gas will be a major contribution to domestic energy supplies, and since obtaining the critical financing for the project is more likely by utilizing rolled-in pricing, we believe it is in the public interest and recommend that rolled-in pricing be adopted.

47/ I.D. 373.

48/ See Financing Brief of Columbia Gas Transmission Corporation, December 7, 1976, p. 15.

49/ See Chapter IV.

F. Field Price For Gas

Several factors indicate the need for an early resolution of the issue of the field price for Alaskan gas. First, according to Judge Litt, the gas producers have set as preconditions to entering into gas sales contracts, ". . .the prior establishment of a sale price, a disclaimer of vintage pricing, 50/and a reversal of Commission policies interpreted by the producers as requiring that they guarantee future minimum delivery volumes regardless of field production capabilities." 51/ Until such time as gas sales contracts are entered into, it will not be possible to determine which gas pipeline and distribution companies will receive the gas and thus which utilities will have an incentive to provide equity financing for a gas transportation system. Without parties willing to supply equity capital, no private financing for the project is feasible. For this reason alone, it is important to determine an appropriate field price as soon as possible.

A second issue relating to the field price for Alaskan gas is whether by deregulation, or by setting a relatively high allowed maximum price, it might be possible to attract gas producer participation in the transportation system financing either directly or through debt guarantees. Such theories of incentive pricing for Alaskan gas are based on the assumption that if gas producers anticipate making substantial profits on the sale of Alaskan gas they would have a greater incentive to have a gas transportation system built. Whether such incentive pricing for Alaskan gas might achieve that objective is currently unknown.

A third issue is the impact of the field price on the delivered cost of gas to consumers. With incremental pricing to distribution companies in direct competition with alternative gas and energy supplies, the field price for Alaskan gas would be approximately the market value of the gas (as perceived by the local distribution company and its state utility commission) minus the cost of transporting it to market. However, the market pressure for a competitive delivered cost is substantially reduced if Alaskan gas is sold to distribution companies on a rolled-in basis with other pipeline

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50/ Vintage pricing is a method whereby gas sold from wells commenced at different periods is priced differently.

51/ I.D. 13.

system supplies. There exists the potential, under rolled-in pricing, for the three major producers to exercise monopoly power to obtain a field price for Alaskan gas in excess of the above difference between market value and the transportation cost. This could occur if pipeline company customers were to enter into long-term shipping contracts obligating them to make minimum payments regardless of the level of gas shipments (i.e., the all-events cost of service tariffs discussed supra), and at the same time enter into gas purchase contracts which allow producers to renegotiate the field price for gas at some intermediate point. Upon renegotiation, producers could require a field price equal to the full incremental city-gate cost of alternative gas supplies since the shippers would be obligated for shipping charges in any event. The remedy is either long-term fixed price contracts or establishment, by contract, of a formula for determining the field price at future dates.

We believe it is imperative that the price of Prudhoe Bay Alaskan gas be established as quickly as possible. We, therefore, propose to establish in the near future a proceeding to determine an appropriate field price for Prudhoe Bay gas as well as to examine the vintaging and throughput agreement issues. If a price were to be set by the Commission, we believe that the cost of gathering and conditioning alone - with a 15% discounted cash flow after tax rate of return on incremental investment related to gas production - would support a field price of about \$0.70 per MMBtu in current dollars (or \$0.50 in 1975 dollars). 52/ If it is found appropriate

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52/ Beginning with the 1975 constant dollar cost of \$1.444 billion for the gas gathering and conditioning facilities (see Chapter IV), and assuming a 5 percent inflation rate and a 15 percent AFUDC rate, the nominal dollar capital cost of the plant would be \$2.44 billion when it is scheduled to go into service in 1983. Allowing a 15 percent after tax rate of return on investment (the same rate allowed gas producers in Opinion Nos. 770 and 770-A), and assuming a 20 year tax life with accelerated depreciation, the annual charge for recovery of and return on investment would be 24 percent of the original investment. Applying this factor to the \$2.44 billion estimated capital cost and spreading the annual cost over 2.25 Bcfd of gas, the cost per Mcf is:

$$\frac{2.44 \times 10^9 \times .24}{2.25 \times 10^9 \times 365} = \$.713/\text{Mcf}$$

(Footnote continued on next page)

to allow recovery of some joint oil/gas costs, the allowed field price would be higher. 53/

We are prepared, however, to examine pricing mechanisms other than setting a fixed price. One possible method for pricing Alaskan gas would be to set the price by the following formula:

Field Price = Market Value - Transportation Cost.

A minimum field price could also be allowed to insure that procucers recover their incremental costs for producing and conditioning gas.

While further evidence would have to be examined before a precise definition of the "market value" indicator for Alaskan gas can be determined, it would most likely be set by reference to the city-gate cost of incremental gas or energy supplies. Arctic Gas witness Schantz stated that on an incremental Btu equivalent basis, distillate fuel oil costs \$2.61 per million Btu at the city gate in 1975 dollars and that natural gas should command a premium above this amount (174/28,658). The Department of the Interior estimated the value to be approximately \$2.62 per

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52/ (Footnote continued from prior page).

In 1975 dollars, at a 5 percent rate of inflation, this charge in 1983 is

$$\$.713 \div (1.05)^8 = \$.48 \text{ Mcf}$$

Assuming 1975 dollar operating and maintenance expenditures of \$15 million per year, adds \$.02 per Mcf:

$$\frac{15 \times 10^6}{2.25 \times 10^6 \times 365} = \$.02 \text{ Mcf}$$

Thus the total cost per Mcf in 1975 dollars is estimated to be \$.50/Mcf for gas conditioning service in 1983. In subsequent years the 1975 dollar cost would be less as inflation erodes the real value of embedded capital costs.

53/ The price to which we are referring in this Chapter is not the wellhead price, but the field price, which includes gathering and conditioning for basic pipeline injection. Furthermore, we are discussing the price for Prudhoe Bay gas and not all Alaskan gas.

MMBtu in 1975 dollars based upon an incremental oil price of $12 per barrel. (EP -231; p. 52). 54/ As for the transportation cost used in the formula, the national average cost to selected major market areas would seem most appropriate.

Besides removing the possibility that producers could exercise monopoly power in the pricing of Alaskan gas, formula pricing would have other advantages over a fixed maximum field price.

First, it avoids the difficult problem of allocating joint costs of gas produced in association with oil, which is the situation in Prudhoe Bay. Current Commission practice is to set prices on non-associated gas, largely on the basis of non-associated gas cost data. Thus, our traditional price-setting methods are inappropriate.

Second, a pricing formula offers consumer significant protection against the possibility of paying a higher than market value for Alaskan gas even when a cost of service tariff and rolled-in pricing for gas are contemplated. Under the formula, transportation cost increases are offset by corresponding reductions in the field price. The result is that the delivered cost of gas (transportation cost + field price) remains equal to the market value of the gas. The one instance in which the above conclusion would not be true is where the field price for gas is reduced to an agreed upon minimum level and the sum of the transportation cost plus the minimum field price exceeds the market value of the gas. In such a situation, we would contemplate a reduction in the allowed return on equity investment in the transportation system to restrain the delivered cost of gas and thus offer consumers additional protection against paying a higher than market price for gas.

54/ If one accepts the Schantz, and Interior Department analyses, and assumes that the relationship between the value of gas and the incremental cost of oil will remain approximately constant in the future, an appropriate indicator of the city gate market value of gas during future periods might be calculated as follows:

$$\text{Market Value (\$/MMBtu)} = \left[\frac{\$2.62 \text{ per MMBtu})}{\$12 \text{ per barrel}}\right] \times \left[\begin{array}{l}\text{Incremental}\\ \text{cost of crude}\\ \text{oil in dollars}\\ \text{per barrel}\end{array}\right]$$

Third, we hope that the upside profit potential offered by the formula approach to pricing as well as the downside protection offered by a minimum wellhead price will stimulate the gas producers to assist in financing the project. Since gas producers' profits on the sale of gas would be equal to the difference between the market value of the gas and the cost of producing and transporting it to market, they would have a direct incentive to see that the transportation system is constructed and operated as efficiently as possible in order to maximize their profits. Such considerations might prompt gas producers to desire some amount of management control over the project and thus to invest some equity capital.

For all of the above reasons, we believe that a formula approach to determining the field price for Alaskan gas has considerable merit. However, under the Natural Gas Act, the authority of the Commission to approve such a pricing procedure under the just and reasonable standard is doubtful. Thus we request that the President submit legislation to authorize the Commission to determine field or wellhead rates for Prudhoe Bay gas on the basis of market factors and alternative fuel prices. So empowered, the Commission could employ such a formula on sales of Alaskan gas from the Prudhoe Bay reserves.

G. Gas Distribution

The distribution of Alaskan gas among potential gas pipeline and distribution company shippers has important economic and financing implications which should not be ignored. While Section 13 of the Alaskan Natural Gas Transportation Act provides for common carrier status for any of the transportation systems, a realistic expectation would be that shippers would make equity investments in any system in proportion to their share of the initial total sales. From a financing standpoint, the large equity investments necessary relative to the financing capabilities of the currently proposed gas utility sponsors 55/ and the chance of significant increases in the price of other flowing gas if consumers are required to make guaranteed debt service payments 56/ argue against a concentration of Alaskan gas ownership.

55/ For example, assuming that sponsoring shipper companies would be required to invest $1.5-$2.0 billion of equity, Columbia Gas Transmission Corporation estimated that under current option arrangements its proportional equity investment could range from $250 million up to $650 million (Financing Brief, December 7, 1976, p. 9). While the exact amount of Alaskan gas which Columbia would receive is not known, it would appear that they contemplate possibly purchasing up to 33% of the proven reserves. The potentially large size of Columbia's required equity investment has resulted in the company taking the position that consumer guarantees of recovery of, as well as, a return on equity investment are required even in the case of project noncompletion or service interruption. T. 182/30,604.

56/ Without being specific, Columbia also argues that the size of the potential increase in gas prices under consumer debt guarantees could be "great enough to jeopardize the competitive position of the sponsoring companies with regard to their ability to market their remaining gas supplies." (Financing Brief, December 7, 1976, p. 4). For these and other reasons, Columbia argues that a Federal Government guarantee to make debt service payments in the case of project noncompletion or service interruption is required. Based on Treasury Department estimates it would appear that the contingent price increase might be as large as $0.30 to $0.40 per Mcf for Columbia's remaining gas flow if that company purchased 25% of the available Alaskan gas supply and consumer debt guarantees were adopted. Ex. ST-58; II-5,6.

Likewise, economic factors argue in favor of a reasonably broad distribution of Alaskan gas. The Department of the Interior has noted the potential for significant economic disruption should Alaskan gas be concentrated in particular markets and an extended service interruption occur (EP-231; p. 141). In addition, some possibility exists that Alaskan gas might be more expensive than alternative gas or energy supplies by the time it is brought to market; a concentration of Alaskan gas in certain domestic markets could have the undesirable effect of locking one area of the country or set of gas consumers into a relatively disadvantageous economic position. Therefore, on both economic and financial grounds, we favor a reasonably broad distribution of Alaskan gas across domestic markets.

The record is inadequate to allow our setting a firm ceiling on the maximum amount of Alaskan gas for which individual companies or market areas would be allowed to initially contract. The need for widespread distribution, however, can be described. A 2.25 Bcf/d Alaskan gas flow rate represents yearly deliveries of 0.82 Tcf. This annual volume compares to total current domestic gas consumption of approximately 18 Tcf, and interstate gas sales of approximately 12 Tcf. Thus, expected initial Alaskan gas deliveries will amount to approximately 4.5 percent and 6.8 percent to total current domestic gas consumption and interstate gas shipments, respectively.

It is extremely unlikely that consumers would be required to repay the entire debt of the project. But in that unlikely event, assuming $7.5 billion of debt outstanding, accelerated repayment of debt over a 7-year period, and a 10 percent interest rate, the Treasury Department calculated potential yearly debt service requirments to be approximately $1.5 billion per year. If consumer debt guarantees are required, and the noncompletion or extended service interruption risk materializes, then using Treasury's assumptions and current gas sales levels the increase in price of other flowing gas to meet debt service on the project would be \$0.086 per Mcf if Alaskan gas were spread evenly over the entire domestic market, or alternatively \$0.128 per Mcf if spread evenly over the interstate market. Should future gas supplies decline by up to 25 percent, then the level of contingent consumer surcharge could increase to between \$0.11 and \$0.17 per Mcf. For average residential customers using approximately 122 Mcf per year, an \$0.11 and \$0.17 per Mcf surcharge would represent a potential increase in gas bills of between \$13 and \$21 per year.

While we would prefer not to have consumers exposed to such risk, we find that it could be justified on the basis that it is necessary to obtain financing for a gas transportation system and thus to obtain a needed new supply of gas. However, we would not want to see potential price increases substantially greater than the range discussed above. Thus, there could be merit in limiting the purchase of Alaskan gas reserves so that the initial anticipated amount of Alaskan gas entering into any particular market area would not exceed, for example, 10 percent of the market's 1976 gas usage. 57/

Assuming that a sufficient number of gas pipeline and gas distribution company sponsors would be interested in participating in the project if they had access to gas, such a limitation on the amount of Alaskan gas flowing to particular markets would also serve to facilitate raising the required equity capital. This could occur by reducing to a more manageable size the proportional equity investments required of each utility. In certificating sales of Alaskan gas, the shipper would be required to project:

1. The financial impact on the company in the case of project failure at an advanced state with total loss of equity investment;

2. The impact on the price of flowing gas if consumers guarantee debt service payments and there is noncompletion or extended service interruption; and,

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57/ Consideration was given to the possibility of allocating Alaskan gas on the basis of end use priorities, but this approach was rejected on the grounds that it is likely only high priority gas users will be supplied by 1985.

3. The economic impacts on their service area in the case of extended service interruptions, or if Alaskan gas is substantially more expensive than alternative energy sources.

Potential gas shippers should proceed from this point under the assumption that the distribution of Alaskan gas in domestic markets must be reasonable from both an economic and financing perspective. If the gas purchase agreements submitted to the Commission for approval meet this standard, there will be no need for direct government action to restrict the initial purchase of gas reserves by certain utilities.

H. Project Sponsor Debt Guarantee Financing Approach

In conjunction with the proposed formula for determining the field price for Alaskan gas discussed herein, and consistent with the Treasury Department position discussed *supra*, the following approach to financing has three express objectives. First is to achieve a successful private financing by providing incentives to stimulate the maximum amount of risk bearing by the projects' potential sponsors. Second is the minimization of the likelihood that consumers will have to pay higher than market value for Alaskan gas, or incur substantial expenses in the case of project noncompletion or extended service interruption. Third is provision of incentives for efficiency in construction and operation of the project.

The essence of this private financing approach is to allow gas producers and project investors the potential of earning profits equal to the market value of the gas less the cost of producing and transporting it to market, while assuring a minimum return on investment as long as minimum gas deliveries are met. In particular, we hope that gas producers, additional gas utility companies, the State of Alaska, and creditworthy corporations looking for an attractive investment58/ will thereby assist in financing the gas transportation system. If such an approach is not successful in attracting both the required equity investments and debt financing guarantees, we would be inclined to endorse consumer debt guarantees only after obtaining a better understanding of why the indicated parties did not participate in the financing more fully.59/

58/ In addition to making the project an attractive investment opportunity, the interest of industrial gas consumers could be enhanced by providing them access to some portion of the Alaskan gas supplies. However, given the importance of Alaskan gas to national supply and its projected base load characteristics in the anticipated markets of 1985 and beyond, such assurances cannot be given.

59/ We would be extremely reluctant ever to permit an all-events cost of service tariff or noncompletion agreement that extended beyond debt service. Throughout the rest of this chapter, all-events cost of service will exclude the return of and return on equity unless otherwise specified

1. Debt to Equity Ratio

The financing plans discussed in the record have generally been predicated on the assumptions that a limited group of gas utilities would supply the needed equity capital and that gas consumers (through an all-events cost of service tariff and noncompletion agreement) or general taxpayers (through government guarantees) would guarantee repayment of the debt financing. Under such assumptions, the relatively high 75/25 debt to equity ratio proposed in the record serves the necessary function of limiting the amount of capital the sponsors have at risk.

However, the financing approach discussed in this section contains neither consumer or general taxpayer debt guarantees. Without such guarantees, the project's capitalization may need to contain a significantly greater proportion of equity capital in order to achieve successful financing.

Major natural gas pipeline companies in the lower 48 States currently operate with capitalizations of about 50 percent equity and 50 percent long-term debt.60/ For purposes of illustrating this private financing approach, we will, therefore, use an assumed 50/50 debt to equity ratio.61/

2. Tariff

Under this financing approach, a cost of service tariff during normal operation would be provided. Under the cost of service tariff, the project would bill gas shippers on a monthly basis, an amount equal to their allocated share of the total dollar cost of service of the transportation system,

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60/ On a consolidated basis, at 12/31/75, the major class A and B pipelines had a captialization of $19.64 billion of which $9.85 billion was long-term debt and $9.79 billion was equity (including $1.03 billion of preferred stock). Data from "Statistics of Interstate Natural Gas Pipeline Companies, 1975" by the Federal Power Commission.

61/ Some portion of the equity financing might reasonably take the form of preferred stock. For illustrative purposes, we will assume only common equity financing.

including operating costs, all taxes, depreciation charges, and a composite weighted rate of return on rate base reflecting the actual capital structure, the actual cost of senior securities, and an allowance on equity. The allowed rate of return on equity would be determined in accordance with a formula such as discussed herein.

If the average level of gas deliveries fell for 30 days below 60 percent of a level defined to constitute normal operation, the tariff would automatically be reduced so as to disallow recovery of a proportional amount of the net plant and working capital accounts. To the extent that lost service could be made up by excess deliveries within one year, shippers would then pay additional charges to reimburse the disallowed capital recovery.62/ These actions are consistent with the intent of this financing approach in that consumers would not guarantee the repayment of equity or debt financing in the case of extended service diminution or interruption, or in the case of project noncompletion. We recognize that the project sponsors, gas producers, the State of Alaska, or other creditworthy corporations would have to stand ready to repay the project's debt financing should project noncompletion or extended service interruption occur. Adequate incentives would be required to induce this action.

We also concur with Judge Litt's recommendation regarding the need for immediate flow through, or so called tracking, of both gas purchase and transportation costs from the project to gas shippers and thence to local distribution companies.63/ In order to accomplish this purpose, the Commission would propose to limit its suspension powers over proposed tariff increases to costs included in the operation and maintenance

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62/ With respect to the issue of reductions in the return on equity for failure to perform contractual service obligations, we concur with Judge Litt's recommendation that if, in any billing month, the transporter accepts from the shipper a volume less than 90 percent of the volume tendered by the shipper pursuant to the shipper's transportation service agreement, there should be a proportional reduction in the shipper's charges for return on equity and income taxes. At service levels less than 60 percent of the volume tendered, no return on equity would be allowed and rate base would be proportionally reduced.

63/ I.D. 406.

expense classifications. 64/ The suspension period would be limited to one day and refunds would be ordered if certain operating and maintenance costs were found to have been imprudently incurred.

3. Rate of Return On Equity

In order to arrange successful private financing--without consumer or government debt guarantees--the project sponsors will have to assume the risk of loss of the total capital cost of the project. For this reason, it will be necessary to establish a rate of return on equity judged by project sponsors and investors to be adequate to compensate them for both placing their equity investment at risk and guaranteeing repayment of the debt financing.

Since the risks of this project are likely to be perceived as greater than those of other gas utility projects previously considered by this Commission, we believe it will be necessary to provide investors an opportunity to earn a higher than usual rate of return. However, we do not favor guaranteeing a high return if the result would be a delivered cost of gas in excess of its market value. 65/ These considerations, as well as the objectives of providing additional incentives for private investment and for efficiency in construction and operation of the project, have led us to conclude that a variable rate of return on equity is appropriate.

64/ There would be no suspension of charges related to recovery of or return on capital investments previously approved as being prudent. See discussion of audit of construction costs, *infra*, p. XII-50.

65/ Under our proposed approach, the delivered cost of gas could exceed the market value of the gas only if the transportation cost was so large that the calculated field price, under the formula discussed herein, fell to its allowed minimum level.

The central questions with such an approach are what is an adequate maximum rate of return on equity? What minimum rate of return on equity would be appropriate? What methodology should be used to determine the allowed rate of return during a particular period?

Unfortunately, the hearing record provides little guidance on these questions other than to demonstrate that with the proposed 75/25 debt to equity ratio and 15-17 percent after-tax return on equity, no party is willing to guarantee the debt. Thus, it is necessary to turn to other sources of information.

The only comparable project of the size and complexity discussed herein that has received private financing is the Alyeska oil pipeline. If that line receives the usual ICC treatment of allowing a 7-8 percent rate of return after taxes and interest on ICC valuation (i.e. total assets), and a 75/25 debt to equity ratio is assumed, the after-tax return on equity would be in the 28-32 percent range. Since, however, the major consideration of the oil producers, who were the ones to finance the oil pipeline, was to get the oil to market, it is difficult to draw any conclusions regarding the rate of return on their pipeline investment they "required" in order to finance it.

An examination of the profitability and financial structure of integrated petroleum companies in general 66/ reveals that over the 1966-1975 period on average these companies earned 11.8 percent after-tax on equity, and during the three year period 1973-1975, earned an average after-tax rate of return on equity of about 14.8 percent. It is important to note that at fiscal year end 1975, this group of petroleum

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66/ The following numbers are derived from Chase Manhattan Bank financial statistics on a group of 28 petroleum companies. See Appendix XII-A for detailed calculations.

companies had approximately a 24 percent long-term debt and 76 percent equity capitalization. Over the period 1966-1975, manufacturing companies67/ averaged an after-tax rate of return on equity of some 11.8 percent, and at year end 1975 had a 25/75 long-term debt to equity ratio. While we do not view the proposed Alaskan natural gas transportation system projects as being as risky as some of the investments of petroleum, or manufacturing companies, we cannot reasonably expect that such companies will risk billions of dollars on this project unless they have the opportunity to earn returns similar to those that they average on alternate projects.

Exhibit XII-1 below displays the relationship between overall pretax return on rate base, debt to equity ratio, and after-tax rate of return on equity for a gas transportation system. At any given overall pretax return, the total transportation cost is relatively independent of the project's D/E ratio, although the proportionate level of taxes, interest payments, and profits do vary considerably. Assuming that there exists some overall expected pretax rate of return on investment adequate to induce potential project sponsors both to make the necessary equity investment and guarantee the debt financing, analysis of the type given in Exhibit XII-1 allows an estimation of the resultant after-tax rate of return on equity for various D/E ratios. Inspection of the Exhibit reveals that a 23 percent overall pretax return on rate base would yield approximately a 13.7 percent after-tax rate of return on equity if the project were financed with a 25/75 debt to equity (D/E) ratio, an 18 percent after-tax return if the project were financed with a 50/50 D/E ratio, and a 31 percent after-tax return with a 75/25 D/E ratio. Such after-tax returns on equity are in line with

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67/ Numbers taken from "Quarterly Financial Report for Manufacturing, Mining, and Trade Corporations," Fourth Quarter 1975, Federal Trade Commission.

EXHIBIT XII-1

RELATIONSHIP BETWEEN OVERALL PRETAX RETURN ON RATE BASE, DEBT TO EQUITY RATIO, AND AFTER-TAX RETURN ON EQUITY

Overall Pretax(a) Rate of Return(%)	After-Tax Rate of Return on Equity(b) D/E=25/75(c)	D/E=50/50	D/E=75/25
23%	13.7%	18%	31%
22	13.0	17	29
21	12.3	16	27
20	11.7	15	25
19	11.0	14	23
18	10.3	13	21
17	9.7	12	19
16	9.0	11	17
15	8.3	10	15
14	7.7	9	13
13	7.0	8	11

(a) Overall Pretax Rate of Return equals income before interest and taxes divided by the rate base.

(b) Assuming a 10% interest rate and a 50% income tax rate.

(c) D/E stands for debt to equity ratio.

the returns petroleum companies currently earn on their integrated operations, and will likely earn on the Alaskan oil pipeline <u>if comparable D/E ratios are assumed</u>. With the minimum return on investment assurances built into the financing approach discussed herein, and recognizing that gas producers stand to make additional profits on the sale of gas, we feel that such rates of return could provide adequate incentives for these companies to make substantial investments. Thus, with the assumed 50/50 D/E ratio, it would appear under current financial market conditions that a maximum 18 percent after-tax rate of return on common equity would be just and reasonable for the project sponsored debt-guarantee financing approach.

For purposes of calculating the equity portion of capitalized allowances for funds used during construction charges during the construction period, an 18 percent after-tax return would be allowed for all prudent expenditures. During the operation period, this return would be allowed so long as the delivered cost of gas (field price + transportation cost) does <u>not</u> exceed the market value of the gas.

However, should the situation occur where the minimum field price plus the transportation cost--calculated on the maximum 18 percent return on equity basis--exceeds the market value of the gas, the allowed rate of return on equity would be reduced as necessary to maintain the delivered cost of gas equal to its market value. In other words, the rate of return would be adjusted so as to equate the transportation cost to the difference between the market value of the gas and the minimum field price. In our opinion, provision for such possible reductions in the rate of return on transportation system investments is appropriate in order both to provide consumers some protection from paying a higher than market value for gas, and provide incentives for efficiency in construction and operation of the project.

On the other hand, in order to provide investors some protection against the project being uneconomic, we are also inclined to allow a minimum return on equity so long as a minimum volume of gas is delivered for a minimum period of time. Such an approach is, of course, consistent with the cost-plus basis on which public utilities are normally regulated. Given the variety of construction and operating risks the project will face, we would recommend a minimum return on equity of 11 percent after tax. While an 11 percent return is lower than those currently allowed for most regulated utilities, the proposed automatic tracking of costs through to the distribution companies means that project equity investors can have confidence that these returns will be realized.68/

The 11 to 18 percent range provides the incentive for the project sponsors to undertake successful efforts to attain high efficiency levels in constructing and operating the project.

Should the situation occur where both the field price for gas and the return on transportation system investment are reduced to their minimum levels, consumers would then begin to pay a price higher than market value for Alaskan gas. Appendix XII-B illustrates and discusses the relationship between the delivered cost of gas, market value of gas, minimum field price, rate of return on equity, and the capital cost of the various projects.

68/ United States regulatory authorities have effective jurisdiction over the entire El Paso project and the Alaskan and lower 48 State segments of the Arctic Gas and Alcan proposals. The 18 percent maximum and 11 percent minimum after-tax return on equity would apply to the U.S. portions of each of these systems. Should the various interested parties indicate a willingness to finance the Arctic Gas or Alcan proposals on the basis discussed herein, application would have to be made to the National Energy Board for similar rate of return treatment. We would hope that Canadian regulatory authorities would deem this approach reasonable.

Finally, should the project sponsors choose to pay other parties a guarantee fee or insurance premium in exchange for bearing a portion of the project's risks, either the operative return on equity would be reduced by a similar amount, or such expenses would not be included in the cost of service tariff calculation, so that the total cost of transportation would remain unchanged regardless of what parties bear specific project risks.69/

4. Audit of Construction Costs

Judge Litt's conclusion that there is a need for an audit of the successful applicant's books during the construction period in order to insure that construction costs are prudently incurred and properly recorded pursuant to the Commission's Uniform System of Accounts is supported by the record. We concur. The details of such an audit, including coordination with the federal inspector appointed under the Alaskan Natural Gas Transportation Act of 1976, will have to be resolved in conference between Federal regulatory authorities and project sponsors.

69/ While the LNG shipping segment of the El Paso proposal is not technically under the Commission's jurisdiction, the contractual arrangements between the shipping company and the Federally regulated shippers are subject to review. By this process, the rate of return on shipping company equity investment will be effectively controlled.

We further would adopt a process by which the Commission would, on a periodic basis, establish definitively whether such construction costs would be permitted to be recovered through the project's tariff. Quarterly audits should be submitted to the Commission which would approve or disapprove the audited costs incurred within 120 days. All costs approved as being prudently incurred would be final and not subject to later disallowance except for fraud or material misrepresentation. Judge Litt noted that under such a periodic approval process:

> ". . . the project company would not be left in doubt until completion whether it would be permitted to recover all of its costs, rapid resolution of the audit process would better afford the project company an opportunity to prospectively correct accounting or procurement error, thus minimizing the chances for disallowed construction costs, and the gas consumer would be protected from excessive and unnecessary costs." (Initial Decision, P. 405).

However, under the financing approach discussed in this section, a Commission certification that certain costs were prudently incurred would not imply that such costs could be recovered from consumers should the project not be completed, or should an extended service interruption occur.

5. Conclusion

In order for the project sponsor debt guarantee financing approach to succeed, parties in addition to the currently proposed project sponsors must agree to bear a portion of the project's risks. We believe that the financing scheme we have outlined herein should offer these parties adequate incentives to make such a commitment. Federal regulatory bodies must, of course, stand ready to work with potentially interested sponsors in order to perfect the details of their financial participation.

We have no specific application before us now indicating that private parties are in fact willing to finance the project on this basis; we cannot even be certain that a financial plan such as that described will be presented for approval. Therefore, we must consider consumer risk bearing actions that may be necessary to secure financing. Furthermore, project sponsor debt guarantees come at a cost. Higher than usual rates of return on equity will be required, and the use of less expensive debt funds may be limited. The alternative is to shift the risk of meeting debt service to the consumers. If such consumer risk bearing is required, we believe they should be compensated. In the next section, we examine what we believe to be a reasonable consumer debt guarantee plan and project its effect on the cost of delivered gas.

I. Consumer Debt Guarantee Financing Approach

The extent to which consumers may have to guarantee project debt service payments in order to arrange financing for an Alaskan natural gas transportation system cannot be known until it is determined if additional creditworthy parties will participate under the project sponsor debt guarantee financing approach. Thus, we feel it is premature to recommend approval of the specific details of the tariff proposals made by the applicants.

Instead we believe it to be more useful to deal conceptually with the various elements of the consumer debt guarantee financing alternative. Measures to protect consumers from bearing unnecessary costs and risks are required and it is appropriate to provide realistic compensation should they bear such risks. Consumers shall not bear a major portion of the project's risk while other parties reap the bulk of the economic benefits.

1. Tariff

As discussed, *supra*, there are four principal tariff component proposals made by the applicants relating to consumer guarantees for the project's financing. First is rolled-in pricing for the sale of Alaskan gas by interstate gas transmission companies to gas distribution companies. As discussed, *supra*, rolled-in pricing of Alaskan gas should be adopted.

The second proposed component is an all-events cost of service tariff under which shippers would enter into service agreements, having a term of 20 years, which would bind them to pay monthly their allocated share of the total dollar cost of service of the transportation systems, including operating costs, all taxes, depreciation charges, and a composite weighted rate of return on rate base. Once the project goes into operation, the all-events cost of service tariff is designed to provide the project adequate cash flow to meet debt service payments and allow recovery of the principal amount of equity investments even in the case of extended service interruption.

The third proposed component is a pre-completion contractual obligation by the prospective gas shippers to make payment of a pro rata share of the project's debt service costs and an allowance for recovery of the project's equity capital if the project is not completed.

The fourth proposed component is approval of automatic tracking of costs incurred under the all-events cost of service tariffs and noncompletion agreements through to gas distribution companies. Such automatic tracking would take the form of a modified purchase gas adjustment clause under which shippers could - on a current basis - flow through to their gas distribution company customers the costs they incur under the all-events cost of service tariff and noncompletion agreement.

In commenting on these proposals, we would begin by making it clear that in our opinion, equity investors should bear the risk of loss of their total equity investment in the event of extended service interruption or non-completion. We fully agree with Judge Litt that neither consumer or taxpayers should guarantee recovery of equity investments since, "The entrepreneur's evaluation of alternative investment opportunities is the primary allocator of investment funds and the great inhibitor of most uneconomic schemes." 70/ Further, Judge Litt's recommendation regarding a reduction in return on equity in the case of failure to perform 90 percent of contractual services obligations made in the private financing approach is appropriate here. In addition, at gas deliveries below a level defined to constitute 60 percent of normal operation, a portion of the net plant and working capital accounts would be removed from the rate base so as to disallow recovery of a proportional amount of the equity investment.

70/ I. D. 300.

If the project sponsors are limited to gas utilities, the record clearly demonstrates that consumer guarantees for debt service payments will be required in order to arrange a successful private financing. 71/ Given that an Alaskan natural gas transportation system has been found to be in the public interest, such consumer debt guarantees would be appropriate in this case. Once the project begins operation, implementation of such guarantees could be accomplished by adoption of an all-events cost of service tariff under which the project could charge gas shippers, and gas shippers could charge their customers, an amount adequate to cover the total dollar cost of service <u>less</u> return on and recovery of equity capital in the event of extended

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71/ Section 13a of the Alaska Natural Gas Transportation Act of 1976 states:

> "...There shall be included in the terms of any certificate, permit, right-of-way, lease, or other authorization issued or granted pursuant to the directions contained in section 9 of this Act, a provision that no person seeking to transport natural gas in the Alaska natural gas transportation system shall be prevented from doing so or be discriminated against in the terms and conditions of service on the basis of degree of ownership, or lack thereof, of the Alaska natural gas transportation system."

Judge Litt (I.D. 426) indicates that it is, "questionable" whether the project could be financed--even with consumer guarantees--unless it were possible to "...limit access to the transportation system to shippers participating fairly in its equity financing." Should a significant number of purchasers of Alaskan gas reserves be unwilling to participate in the financing of the project, then deletion of Section 13a may be required.

service interruption. 72/ Prior to completion of the project, the consumer debt guarantee would take the form of noncompletion agreements whereby gas shippers would be committed to making payments to the project entity adequate to cover debt service payments in the event that the project was not completed. Federally regulated gas shippers would be authorized to flow through such payments to their customers on a current basis. 73/

2. Rate of Return on Investment

If consumer guarantees for debt service payments 74/ are provided, then it is obvious that the financial risk assumed by project sponsors is substantially reduced. For example, with the 75/25 debt to equity ratio suggested in the record, the number of dollars sponsors have at risk in the case of noncompletion or extended service interruption is one-fourth the amount discussed under the private financing approach where they must both make the required

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72/ Section 13b of the Alaskan Natural Gas Transportation Act of 1976 allows the State of Alaska to withdraw its royalty gas from the interstate market for use within Alaska. Should this event occur, we would recommend that the State of Alaska should ship its royalty gas under terms similar to all other gas shippers.

73/ Under the Arctic Gas, and possibly the Alcan proposal, if a significant portion of the facilities are devoted to the transport of Canadian gas to Canadian markets, then United States regulatory assurances that a proportional amount of debt service costs could be recovered from U.S. consumers would not be adequate to accomplish a financing for the entire project. Under such circumstances guarantees by creditworthy parties would be needed for the Canada's share of the Canadian facilities.

74/ Similar considerations apply for Federal Government debt guarantees.

equity investment and guarantee repayment of the debt capital. An appropriate rate of return on equity investment should, of course, reflect this reduction in financial risk.

During the course of the hearings, the applicants generally use a 15-17 percent after-tax rate of return on equity as a suggested rate of return. These returns assumed, among other things, a cost-of-service tariff, consumer or general taxpayer debt guarantees, and provision for recovery of equity investment in the case of project failure. Under similar assumptions, Staff suggested a 10.5 percent rate of return on equity. (155/25,584).

A factor apparently ignored in the hearing record is that if consumers or taxpayers assume the risk of repayment of the project's debt financing, then the project's sponsors have an increased opportunity to "leverage up" their equity investments in the project. A typical gas utility project would be financed with equity capital plus debt financing guaranteed by the sponsoring company. Assuming a 50/50 debt to equity ratio, and typical rates of return on equity, the sponsoring company might earn 12 to 13 percent after tax on the equity portion of the financing which is 50 percent of the total capital at risk. In the case of a project to be undertaken where consumers have effectively guaranteed repayment of the debt capital, the situation is completely different. Rather than earning an equity return on 50 percent of the capital at risk, sponsors earn an equity return on 100 percent of the capital they have at risk. Thus, if the sponsor's investment in the project is funded with a mix of sponsoring company equity and debt financing, the after return on the sponsor's equity capital could be significantly higher than the stated return on project equity investments. 75/

75/ For example, assuming the project sponsors finance their investment in an Alaskan gas transportation system with 50 percent parent company equity plus 50 percent external debt financing, that the effective tax rate on dividend payments by the project to sponsoring companies is 7.5 percent (reflecting the 85 percent dividend received credit), and that the effective after-tax cost of parent debt financing is 5 percent, then with an 11 percent after tax return on project equity investments,

(Footnote continued on next page)

Given the greater risks of an Alaskan natural gas transportation system relative to typical gas utility projects, we feel it is appropriate for the sponsoring companies to have the opportunity to earn higher than normal returns. Therefore, we would recommend that - if consumer debt guarantees are required - the rate of return on Alaskan gas transportation system equity investments be determined generally as discussed under the project sponsor debt-guarantee financing approach except that the maximum rate of return would be 15 percent and the minimum return would be 11 percent.

(Footnoted continued from prior page)

the effective return on parent equity capital is approximately 15.3 percent after tax. Such a return compares favorably to those on typical gas utility projects.

Assuming a $100 investment in an Alaskan gas transportation system, the return on parent company equity can be estimated as follows:

After-tax profit on project equity investment = ($100) (0.11)	= $11.00
Less income taxes on project dividend payments to parent company = ($11) (0.075)	= 0.83
Less after-tax cost of parent company debt financing = ($50) (0.05)	= 2.50
After-tax profit on parent company equity	= $ 7.67
After-tax return on parent equity = $7.67/$50	= 15.3%

3. Consumer Surcharges

Arctic Gas argues, and Judge Litt concurs, 76/ that some type of preoperation surcharge on gas consumers is needed in order to provide regulated-equity investors with adequate cash flow to cover the carrying cost on their large investments during the construction period. Such surcharges are envisioned to take the form of consumer loans with a clear obligation for repayment with interest, even in the case of project failure.

As a general proposition, we agree with the Federal Power Commission Staff's position that if the currently proposed group of project sponsors do not have the capacity to finance the required equity investment, then additional participants should be added to the consortium so as to reduce the financing demands on each sponsor and therefore, permit traditional financing. We believe that the project sponsor debt-guarantee financing approach, if adopted, would result in the attraction of additional sponsors and that preoperation surcharges would be unnecessary. 77/ Nevertheless, given the size of the project and the potential for cost overruns, we can envision circumstances under which such a surcharge to assist in financing this unique project would be required and could be in the public interest.

One such instance where a consumer surcharge would be warranted is if the project is unable to attract additional sponsors to the project. If this is the case, then we would support Judge Litt's finding that:

76/ See I.D. 393-400.

77/ There is no inherent reason, though, why surcharges could not be used in this context.

> "The need for some tariff mechanism to generate cash flow to finance equity investment has been established. No attempt will be made at this point in the case to choose among those methods discussed in the record, or to fashion a more acceptable method. Method 4 proposed by the Arctic Gas 78/ sponsors may well constitute the basic guide for crafting an appropriate provision." (I.D., 400) (Footnote added).

A second instance where a preoperation surcharge could prove necessary is if it turns out that the sponsors have been overly optimistic in their assessment of the amounts of money that can be raised in various capital markets. While it is clear that in aggregate size, the United States and other targeted capital markets have the required capacity to finance the project, ". . . several aspects of the financial plans press to the very edge of what has been accomplished by past utility financings." 79/ A successful financing apparently will require the participation of most major financial institutions in the United States, and possibly Canada, with additional support from international capital markets needed in some instances. Many factors will affect the decisions of these large institutions, including in particular, the state of capital markets at the time the financing is being arranged and their analysis of the credit backing provided for debt investments. We cannot

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78/ Under Method 4 each sponsoring pipeline subject to FPC jurisdiction would annually charge its customers a percentage of its accumulated equity investment in the project companies; the charge would generate enough cash to cover the carrying cost of each of the sponsor's investment. The charges would be refunded with interest over a period of time after operations commenced.

79/ I.D., 356

rule out the possibility that adequate amounts of financing may not be available to the project. Under such circumstances, the option of directly financing a portion of the capital cost of the project by a consumer surcharge should be maintained. For example, a consumer surcharge might be used to finance the interest cost on debt funds used during construction.

A third instance in which a consumer surcharge could be needed is in the case of substantial cost overruns. In particular, if a consumer noncompletion guarantee is required, then it is clear that some mechanism to allow for consumer surcharges to finance completion of the project will be needed as an alternative to a similar surcharge to repay debt financing in the case of project noncompletion. As with other aspects of the financing for this project, it is premature to reach a final conclusion on what, if any, consumer surcharge financing arrangements may prove necessary.

One potential stumbling block to the use of such consumer surcharges to assist the financing of the project is the tax treatment afforded the surcharge collections by the gas shippers and gas distribution companies. If these funds are treated as taxable income to gas utilities, rather than as consumer loans, then the size of the required surcharge necessary to generate any level of capital would approximately double. Some way to moderate this tax problem is a prerequisite to final adoption of the consumer surcharge approach.

Preliminary discussions between the Commission Staff and the Department of the Treasury indicate that a carefully structured surcharge to certain customers might be treated as a loan transaction. A particularly troublesome problem is that commercial and industrial gas consumers are likely to be able to treat surcharge payments as a tax deductible expense. In this instance, there would seem to be no realistic alternative to treating surcharge collections as current income to the gas utilities collecting the surcharge. On the other hand, residential gas consumers cannot treat a surcharge as a tax deductible expense and thus if properly cast it may be possible to treat these surcharges as a loan transaction. While the particulars of such an approach remain to be worked out, it could involve setting up an independent trustee to insure that consumers' financial interests are protected. The trustee would receive surcharge collections, make loans to the project entity (or project sponsors), receive principal and interest payments on the loan, pay a predetermined tax rate on the interest income, and insure that loan principal payments plus after-tax interest income is channeled back to consumers in proportion to the original surcharge collections from particular gas distribution systems.

Additional work between Federal Power Commission Staff and the Treasury Department is required on this issue.

4. Consumer Benefits for Risk-Bearing

We believe that should consumers be required to bear a major portion of the risks of the project being uneconomical, or repaying debt financing in the case of extended service interruption or project noncompletion that they should also pay lower rates than those which would be paid if others were bearing these risks. This idea was advanced by the Department of the Treasury. 80/

Should consumer debt guarantees prove to be necessary in attracting private financing, and should the proposed formula approach to establishing the field price for

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80/ See ST-58; p. III-3.

Alaskan gas be adopted, 81/ then we recommend adoption of a consumer guarantee fee. The guarantee fee would be approximately equal to the difference between the cost of service if the project were financed under the project sponsor debt guarantee approach and the cost of service under a consumer debt guarantee form of financing. 82/ For purposes of calculating the gas field price under the formula discussed herein, the consumer guarantee fee would be added to the out-of-pocket transportation cost and thus the allowed field price would be approximately the same whether the "Sponsor" or "Consumer Debt

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81/ Alternatively, if the field price for Alaskan gas is set and maintained at a fixed level based on estimated production and conditioning costs plus a fixed return on investment, then consumers are compensated directly if the transportation system's cost of capital is reduced as a result of adoption of consumer debt guarantees. In this instance no consumer guarantee fee would be needed. However, as discussed herein, we believe there are strong reasons in favor of adopting a formula for determining the field price for Alaskan gas.

82/ If a consumer guarantee fee were not adopted, and subsequently Alaskan gas field prices were deregulated or set on the basis of the formula discussed, supra, then the gas producers would receive the benefit of the reduced transportation cost resulting from consumer debt guarantees. This result occurs because a lower transportation allows a higher field price.

Guarantee" financing approaches are utilized. 83/ However, since the delivered cost of gas is equal to the sum of the field price for gas plus the out-of

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83/ To illustrate, the allowed field price would be calculated as follows:

Field Price = Market Value - Transportation Cost - Consumer Guarantee Fee

Where:

Field Price = Price paid to producers for gas after conditioning and ready for shipment ($/MMBtu)

Market Value = City-gate market value for gas ($/MMBtu)

Transportation Cost = National average transportation cost for Alaskan gas calculated with a 75/25 debt to equity ratio and 15 percent after-tax return on equity ($/MMBtu)

Consumer Guarantee Fee = Transportation cost calculated at a 50/50 D/E ratio and 18 percent return on equity less transportation cost calculated at a 75/25 D/E ratio and 15 percent return.

pocket transportation cost, consumers would receive gas at a delivered cost lower than market value, 84/ as compensation for their risk bearing.

Under the sponsor debt-guarantee financing approach, assuming a $10.0 billion capital cost, a 50/50 debt to equity ratio, an 18 percent after-tax return on equity, and a 10 percent interest rate on debt, the <u>first year</u>

84/ To further illustrate, assuming that the minimum field price was not operative, the reduction in the delivered cost of gas below market value would be equal to the size of the consumer guarantee fee.

Delivered cost to Consumers = Field Price + Transportation Cost (At 75/25 D/E and 15 percent after-tax return on equity)

= Market Value - Consumer Guarantee Fee

Once the minimum field price is in effect, then the reduction in the delivered cost of gas would be equal to:

Market Value - Minimum Field Price
- Transportation Cost Calculated at 15% return on equity

Should the sum of the minimum field price and transportation cost calculated at 15% after tax return on equity exceed the market value of the gas, then the rate of return on equity would be reduced as necessary (down to the minimum return of 11 percent) to maintain the delivered cost equal to the market value.

pretax cost of capital payments included in the project's cost of service would be approximately $2.3 billion. 85/ Under the consumer debt guarantee financing approach, with a 75/25 debt to equity ratio, and a 15 percent return on equity, the first year pretax cost of capital payments would be approximately $1.5 billion. 86/ At a gas flow rate of 2.25 Bcf/d, or 821 million Mcf/year, the first year (1983) consumer guarantee fee would work out to be approximately $0.97 per Mcf in nominal dollars 87/ or $0.66 per Mcf in 1975 dollars. 88/ Of course, as the project's debt financing is repaid, the aggregate amount of the consumer guarantee fee would decline proportionately; similarly, if the level of gas shipments increase, the per Mcf size of the fee decreases. Such a fee would be equal to approximately 11 percent of the project's outstanding debt. 89/

85/

Pretax return on equity	= $5.0 B x 0.36 =	$1.80 B
Interest Expense	= $5.0 B x 0.10 =	$0.50 B
Total Pretax Cost of Capital		$2.30 B

86/

Pretax return on equity	= $2.5 B x 0.30 =	$0.75 B
Interest Expense	= $7.5 B x 0.10 =	$0.75 B
Total Pretax Cost of Capital		$1.50 B

87/ ($2.3 B - 1.5B) / 821 million Mcf = $0.97/Mcf

88/ Assuming a constant 5 percent inflation rate.

89/ ($2.3 B - 1.5 B) / $7.5 B = 0.107.

Based on the foregoing illustration and the assumptions therein, the annual consumer debt guarantee fee would be set at 11 percent of the project's average outstanding debt - both short and long term. During the construction period, the fee would be accrued and once the project goes into operation the accrued guarantee fee would be amortized over 20 years with interest. 90/ In addition, during each month of the project's operation, a guarantee fee equal to 0.92 percent 91/ of the project's average outstanding debt would be assessed. Both the monthly guarantee fee and the amortized portion of the accrued guarantee fee would be added to the out-of-pocket transportation cost for purposes of calculating the allowed field price for gas.

In addition, should consumer surcharges be deemed necessary, the repayment of these surcharges with interest would further reduce the cost of gas to consumers. If such consumer loans are made directly to a project sponsor with a clear repayment obligation - even in the case of project failure - then an appropriate interest rate should approximate the one at which that company could borrow money in the capital markets on a long-term unsecured basis. However, if the consumer loans are to the project entity with no guarantee of repayment by any creditworthy party in the case of project failure, then, to be consistent with the consumer debt guarantee fee discussed above, the interest rate on such consumer loans should be set equal to the weighted average rate of return on the project's outstanding long-term debt plus 11 percent. While such interest rates may seem high, it should be kept in mind that the consensus of the expert financial testimony is that without guarantees of creditworthy parties, the risks of the project are such that debt financing for the project from traditional capital markets would simply be unavailable at any interest rate.

90/ An appropriate interest rate on the accrued guarantee fee would seem to be the weighted average interest rate on the project's long-term debt outstanding at project completion.

91/ The monthly guarantee fee of 0.92 percent is equal to approximately one-twelfth of the suggested annual fee of 11 percent.

5. Actions to Protect Consumer's Financial Interests

The all events tariff, noncompletion agreement, and consumer surcharge represent a completely new level of financial risk bearing by gas consumers. In effect, consumers are either guaranteeing the repayment of the project's debt financing, or making investments directly in the project. Under such circumstances, the issue of protecting consumer's financial interests, requires careful consideration. In our opinion, the desirability of utilizing such innovative regulatory devises depends substantially on adoption of various measures which protect consumers from bearing unnecessary costs and risks.

We believe the project must be structured so that the financial and economic impacts on gas consumers and regulated utilities of project failure are tolerable on a company-by company basis. If required, we would be prepared to set limits on the initial purchase of Alaskan gas reserves to insure a reasonably broad distribution across domestic markets.

In addition, as indicated throughout this decision, we would expect the project's equity investment to be at risk in the case of noncompletion, or service interruption. With respect to minimizing consumers' contingent liability we propose to exclude from protection under such an agreement a subsequently to be determined fixed dollar amount approximately equal to the equity component of the project capital. Thus if the project were aborted prior to the expenditure of that amount, the consumer would have no liability under the noncompletion agreement. Further, we propose to limit the consumers' noncompletion liability to approximately 75 percent of total prudently incurred cost.

Federal regulatory authorities should also retain the residual power to terminate the all events cost of service tariff, noncompletion, and consumer surcharge arrangements with regard to prospective expenditures, should extraordinary cost overruns occur and it becomes uneconomic to complete the project. All parties concerned will undoubtedly require the establishment of objective standards for determining when Federal regulatory authorities would be empowered to terminate the tariff arrangements. 92 /

Finally, the economic viability of any of these huge projects require the availability of substantial quantities of gas for shipment. If customers assume the risk or repaying the project's debt financing in the case of extended service interruption, it would be desirable to have a contractual commitment by the producers regarding the minimum average daily volume that will be delivered to the shipper so that the extent of the consumer' risk can be better assessed. We understand that similar through-put guarantees were made in the Alaskan oil pipeline financing. If gas producers are confident about their ability to supply adequate amounts of gas to justify building a gas transportation system then entering into an agreement would pose little risk to these companies. On the other hand, if the producers have significant uncertainties about the minimum deliverable volumes of gas, Federal decisionmakers and project sponsors should know the full details of such uncertainties before finally approving the design of the authorized system and proceeding with the project.

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92 / Staff also considered the possibility of requiring the successful applicant to demonstrate - early in the proposed construction schedule - the economic feasibility of large-scale winter construction under Arctic conditions but concluded the information which might be obtained from such a program would itself be of questionable value.

6. Actions to Reduce Regulatory Risk

The following actions would reduce the level of regulatory risk faced by project sponsors and investors. First, a procedure should be adopted whereby Federal regulatory authorities would periodically make a definitive ruling as to whether costs during a given portion of the construction period were prudently incurred. Second, if all events cost of service tariffs, and/or noncompletion agreements are required, we would support legislation to bind future Federal regulatory authorities to maintain and enforce such arrangements. 93/ Third, subject to reserving the right to review whether costs were prudently incurred 94/ and allowable under the all events tariff, we would support the passthrough of costs on a current basis (see discussion, *supra*, p. XII-43; and also support legislation binding authorities to maintain this treatment.

With respect to the issue of regulatory risk at the State level, we believe it is essential that Federal government maintain a dialogue with State Utility Commissions to discuss the alternatives for financing an Alaskan Natural Gas Transportation System. It may even prove useful for the government to sponsor a conference in the near future. This conference would, among other things, consider the issues of regulatory risk at the State level, and what timely actions might be taken by the States to alleviate investor concerns. A principal topic of discussion would be alternatives to, and the need for, Federal legislation to assure the flow through of approved costs at the gas distribution company level.

93/ While El Paso makes a strong legal argument that such legislation is unnecessary, the enactment of legislation would remove any lingering doubts that lenders and project sponsors might have.

94/ Capital costs previously determined to be prudent during the periodic audit of construction expenditures would not be subject to review except in the case of fraud or material misrepresentation on the part of the sponsoring companies.

J. Financial Plan Feasibility

Each applicant has submitted studies and expert financial testimony to the effect that, with adequate credit backing, their particular project can be financed in the private capital markets. We agree with Judge Litt that given ". . . the different guidelines that are certain to be in place when the successful applicant seeks to firm up final financial plans for Commission approval, the detailed record discussion of the feasibility of existing plans takes on less significance." 95/ This conclusion clearly applies if the sponsor debt guarantee financing approach attracts substantial participation by additional creditworthy parties, and the project's debt to equity ratio is decreased significantly.

Nevertheless, the sheer magnitude of the required financing is such that the applicants have often been at odds with each other over the capacity of certain capital markets and what in fact will be required in order to arrange a successful fiancing. For this reason, a brief review of the existing financing plans as displayed in the following tables is found to be useful. It should be noted that Arctic Gas and El Paso's financing requirements are generally stated in terms of 1975 dollars, while Alcan has chosen to state its financing requirements in escalated dollars. It should be further noted that during the construction period, each project would make extensive use of short-term bridge financing which is not apparent from the tables displaying sources of funds at completion.

Given adequate identical tariff provisions, the El Paso financing plan appears to be the most feasible. 96/ In particular the anticipated availability of Title XI Federal ship financing guarantees will increase El Paso's access to loans from U.S. pension funds. Further, El Paso does not have to contend with the issue of the so-called "Canadian Basket" 97/ under which U.S. life insurance companies are limited in their overall ability to make

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95/ I.D. 374 (constant 1977 pagination).

96/ The Initial Decision reached the same conclusion: See p.378.

97/ Under New York law, insurance companies operating in that State (virtually all major companies) have their Canadian investments limited to 10 percent of admitted assets.

ARCTIC GAS (Source of Funds at Completion) 1/
(Millions of 1975 $)

	Alaskan Arctic	Canadian Arctic	Northern Border	PGT & PG&E 2/	Trans-Canada 3/	Total
Banks						
U.S.	132	311	192			635
Canada		500				500
Long-Term Debt						
U.S.	315	1,850	603	508		3,276
Canada		850 4/			694	1,544
Export Credits		500				500
Euro Credit Bonds		200				200
Equity						
U.S.	150	699	267			1,116
Canada		701			49	750
TOTAL	597	5,611	1,062	508	743	8,521 5/

1/ Illustrative of Financing requirements for 2.25 BCF/D Alaskan and 1.0 BCF/D Mackenzie gas flow rate case. Data taken from the Initial Decision P.262.

2/ PGT and PG&E were not considered by Arctic Gas but are in this table; although project financing might not be required for the 1580 design, this western leg is an integal part of the project as a whole. Alcan includes PGT and PG&E.

3/ Arctic Gas excluded the financing requirements of Trans-Canada. These capital costs of enlarging Trans-Canada to handle Mackenzie Delta gas transported by Canadian Arctic must be considered for financial analysis.

4/ $350 million to be privately placed with insurance companies and $500 million publicly placed.

5/ This total does not include any contingency financing and it generally represents 1975 dollars. In its Brief on Exceptions (P.62) to the Initial Decision, Arctic Gas contended that the Financing requirements shown above for Alaskan Arctic, Canadian Arctic, and Trans-Canada were stated in escalated dollars. A review of Exhibits AA-38 and AA-11 indicate that the Alaskan Arctic and Canadian Arctic financing requirements are correctly stated in 1975 dollars. However, the use of escalated costs for Trans-Canada overstates Arctic Gas capital costs to some degree.

EL PASO (Source of Funds at Completion)1/
(Millions of 1975 $)

	Alaskan Facilities	LNG Fleet	Western LNG	East of California	Total
U.S. Border	270 2/				270
U.S. Life Insurance Cos.	1,600		528	217.8	2,345.8
U.S. Pension Funds	400	1,049.2			1.449.2
Debentures	250				250
Equity Sponsorship	1,031.4	427.1	155.4	72.5	1,686.4
TOTAL	3,551.4	1,476.3	683.4	290.3	6,001.4 3/

1/ Financing for 2.4 BCF/D gas flow rate case; Data taken from the Initial Decision P.262, and El Paso's Brief on Exceptions P.262.

2/ This $270 million is the outstanding balance of El Paso's $1 billion revolving credit agreement which would be converted into a term loan. Moreover, Western LNG plans to make short-term bank borrowings of $150 million.

3/ With the equity portion of AFUDC, this total is $6,500 million (1975 dollars). No contingency financing has been included by El Paso.

ALCAN 48 INCH ALTERNATIVE PROPOSAL 1/ (Financing Requirements)
($ Millions) 2/

	Foothills (Yukon)	Alberta Gas Trunk Line (AGTL)	Westcoast	Alcan	PG&E	PGT	Northern Border	Total
Banks								
U.S.	—	—	—	563	—	—	290	853
Canada	325	160	17	—	—	—	—	502
Long-Term Debt								
U.S.	475	425	590	1,900	388	364	921	5,063
Canada	200	245	310	—	—	—	—	755
Equity								
U.S.								
Preferred	205	135	—	—	—	—	—	340
Common	—	—	—	840	—	—	402	1,242
Canada								
Preferred	—	—	150	—	—	—	—	150
Common	140	115	150	—	—	—	—	405
TOTAL	1,345	1,080	1,217	3,303	388	364	1,613	9,310 3/ 4/

1/ Data taken from "Submittal of Alcan Pipeline Company at Docket No. RM77-6," Before The United States of America Federal Power Commission, March 1977; Section 8, P.8.

2/ Financing requirements are stated in escalated dollars; estimated cost overrun contingency not included.

3/ Alcan would reduce this amount by $170 million due to claimed duplications between AGTL and Westcoast.

4/ Some parties have argued that one should also include the projected capital cost of the Maple Leaf Project when considering the feasibility of financing the Alcan project; we have chosen not to do so under the theory that Alcan is a self-contained project and if once started would be financed to completion even if this resulted in some delay in the financing of the Maple Leaf Project.

investment in Canadian companies. However, El Paso's greatest financing advantage may be that it would operate solely under the regulatory supervision of the United States. Operating under a single regulatory authority makes it easier to implement innovations such as the variable rate of return on investment or all events tariff concepts, which may prove to be essential in arranging a private financing.

Unresolved issues with respect to the El Paso financing plan include the proposed sale of $350 million of capital notes to the project sponsors, and the issuance of preferred stock in lieu of accumulating the equity portion of AFUDC charges during the construction period. If other project sponsors refuse to go along with these proposals, El Paso's final financing plan would have to be modified accordingly.

Arctic Gas plans to raise debt financing in the U.S. and Canadian banking and long-term debt markets, as well as the EuroDollar Market and export credits from international sources. While the proposed Arctic Gas financing plan would press the limits of certain U.S. and Canadian capital markets 98/, it would appear that a successful financing could be accomplished if adequate credit backing for the project's debt financing is available. 99/

Of the three applicants, Alcan's financing plan has been the subject of the greatest criticism. A principal

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98/ See Appendix I to the Initial Decision for a fuller discussion of these issues.

99/ While any of these projects are huge in absolute terms, they are small in relation to the aggregate size of the United States capital markets. For example, in a study entitled "United States Capital Market Capacity", Morgan Stanley and Company projected that the total net funds raised by corporate nonfinancial businesses would average about $100 billion per year over the 1975-79 period.

attack has been that both the Alcan and Maple Leaf projects cannot be financed during the same time period, 100/ and that one or the other of the projects may have to be delayed somewhat to accomplish a successful financing. If Alcan suffers such a delay, any inflation related cost increase would have to be absorbed by U.S. consumers.

A second basic attack on the Alcan financing plan is the proposal that U.S. shippers supply in excess of 50 percent of the equity financing for the Foothills and Alberta Gas Trunk Line segments in exchange for non-voting stock which some potential shippers consider to have a low yield. We have no intention of forcing U.S. shippers to accept such a proposal, and believe that the project sponsors must work out a satisfactory compromise if the final Alcan financing plan is to be found acceptable.

100/ The Canadian sponsors of Alcan are also proposing to build the Maple Leaf project which would require additional financing of some $3,303 million (including $743 million for needed expansion of the TransCanada pipeline). See Chapter II.

APPENDIX XII-A

PROFITABILITY AND FINANCIAL STRUCTURE OF INTEGRATED PETROLEUM COMPANIES 1/

($ Millions)

COLUMN 1 Year	COLUMN 2 Net Income After Tax 2/	COLUMN 3 Net Worth 2/	COLUMN 4 After-Tax Return on Equity (%) (Col. 2÷Col. 3)	COLUMN 5 Long-Term Debt	COLUMN 6 Total Capitalization (Col. 3+Col. 5)	COLUMN 7 Long-Term Debt to Total Capital Ratio (Col. 5÷Col. 6)
1966	5,732	52,859	10.8%	8,612	61,471	14.0%
1967	6,206	56,392	11.0	10,565	66,957	15.8
1968	6,752	59,999	10.9	13,187	73,186	18.0
1969	6,760	63,570	10.6	14,864	78,434	19.0
1970	6,701	66,885	10.0	16,756	83,641	20.0
1971	7,328	70,838	10.3	19,339	90,177	21.4
1972	6,898	72,514	9.5	20,283	92,797	21.9
1973	11,766	80,100	14.2	20,813	100,913	20.6
1974	16,558	92,446	17.9	23,092	115,538	20.0
1975	11,977	96,874	12.4	30,645	127,519	24.0
Average 1966-1975	N.A.	N.A.	11.8	N.A.	N.A.	N.A.
Average 1973-1975	N.A.	N.A.	14.8	N.A.	N.A.	N.A.

1/ Data from Chase Manhatten Bank financial statistics on a group of 28 petroleum companies. Data base changed to 29 companies in 1975.

2/ Includes minority interest.

APPENDIX XII-B

Exhibit XII-2 below illustrates the relationship between the market value of gas, field price for Alaskan gas, capital cost of project, rate of return on transportation system investment, and delivered cost of gas under the sponsor debt guarantee financing approach. In order to simplify the discussion, the following assumptions were made:

1. All numbers are given in terms of 1975 dollars.

2. The market value of gas is assumed to be $2.65 per MMBtu over the life of the project. 101/

3. The minimum field price is assumed to be $0.50 per MMBtu (as discussed herein the nominal dollar minimum field price would likely be at least $0.70 per MMBtu).

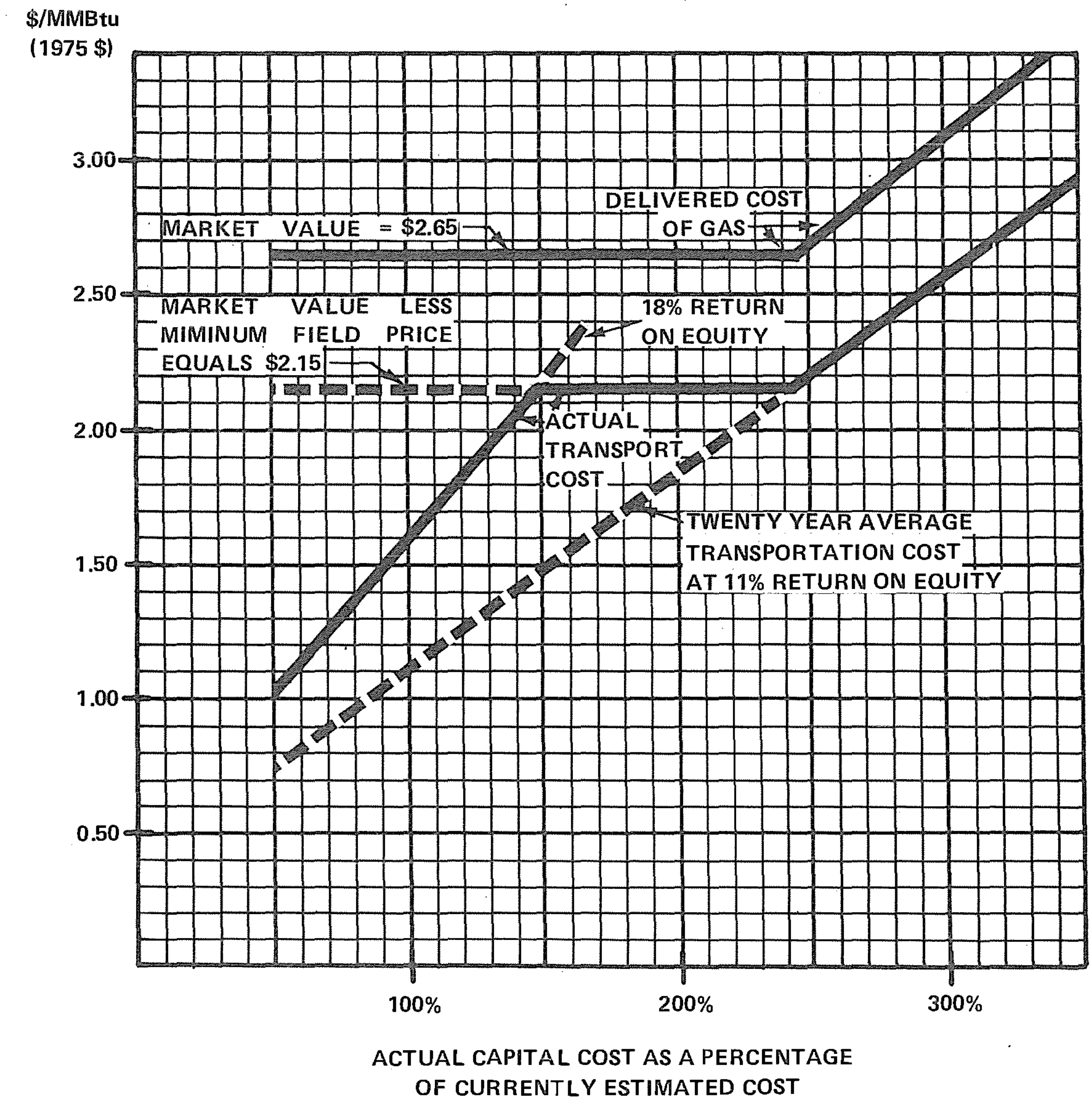
4. Twenty-year average cost of service numbers were employed. While the specific cost of service figures used do not apply to a particular project, they were selected from the higher range of estimates supplied by the sponsors. Staff adjusted the capitalization to an assumed 50/50 debt to equity ratio and then determined the cost of service for various rates of return on equity and capital costs.

5. A constant Alaskan gas flow rate of 2.25 Bcfd.

101/ This assumed market value is consistent with that used in the net national economic benefit analysis contained herein. Of course, under the proposed formula approach to determine the field price for Alaskan gas, the actual "market value" indicator would be changed periodically as the cost of alternative energy sources changes.

EXHIBIT XII - 2

ILLUSTRATION OF RELATIONSHIP BETWEEN MARKET VALUE OF GAS, FIELD PRICE FOR ALASKAN GAS, CAPITAL COST OF PROJECT, RATE OF RETURN ON EQUITY INVESTMENT, AND DELIVERED COST OF GAS UNDER THE SPONSOR DEBT GUARANTEE FINANCING



With these assumptions in mind, the following observations can be made regarding Exhibit XII-2. If the project is constructed at a capital cost equal to 100 percent of current estimates, the average transportation cost is $1.60 per MMBtu. With a market value of gas of $2.65 per MMBtu, and employing our proposed formula, the average field price for gas would be calculated to be $1.05 per MMBtu ($2.65 - $1.60).

As the capital cost of the project increases, the actual cost of transportation--calculated on the basis of 18 percent return on equity--increases, and under the proposed formula, the field price for Alaskan gas declines. At a capital cost of approximately 145 percent of the currently projected cost, the transportation cost has risen to the point where the field price for gas has been reduced to its minimum level. To this point, the delivered cost of gas has remained constant at $2.65 (i.e. the assumed market value of the gas).

For capital costs between 145 percent and about 245 percent of currently estimated cost, the actual transportation cost is maintained at the constant level of $2.15 per MMBtu by reducing the allowed return on equity investment from 18 percent to 11 percent. In this interval, the field price for Alaskan gas also stays constant at $0.50/MMBtu, and thus the delivered cost of gas (i.e. the sum of the actual transportation cost plus the minimum field price) continues to equal the market value of gas, or $2.65 per MMBtu.

For capital costs in excess of 245 percent of current estimates, the actual transportation cost calculated at the 11 percent minimum return exceeds $2.15 per MMBtu, and thus the delivered cost of gas exceeds the market value of the gas.

Similar graphs utilizing five-year average transportation costs would show that--during the early years of the project--producers and project equity investors would begin receiving the minimum field price and minimum return on equity investment at smaller cost overrun levels. Conversely during the latter years of the project, investors would be able to earn the maximum rate of return on equity and gas producers receive higher than the minimum field price at larger cost overruns.

CHAPTER XIII

TERMS AND CONDITIONS

The Alaska Natural Gas Transportation Act of 1977 §5(e) provides that a Commission recommendation of a particular transportation system shall be accompanied by "the terms and conditions permitted under the Natural Gas Act, which the Commission determines to be appropriate for inclusion in a certificate of public convenience and necessity." We have determined that terms and conditions should be imposed respecting the protection of the environment and adherence to certain technical specifications during the construction and operation of the system.

This Recommendation constitutes only the initial phase of the process by which the choice among the competing systems will be made. Since the transportation systems are quite diverse with respect to routing, technology and mode, it is not possible to specify at this time detailed and site-specific terms and conditions that would be applicable to all systems. Therefore, additional consideration must be given to conditions at, or soon after, the time a final decision on a system is made. Nevertheless, it is possible at this time to indicate the nature of the terms and conditions that we believe to be appropriate, whichever system is ultimately selected.

The enclosed draft terms and conditions have been through a preliminary review process. An initial draft was prepared by FPC Staff with assistance of the Department of Interior, and sent on February 15, 1977, to 22 Federal agencies for review. The comments were incorporated into a second draft, 2,000 copies of which were distributed on March 10, 1977, to all agencies and persons that had received the Final Environmental Impact Statement for the Alaska Natural Gas Transportation System and to all parties to the FPC certificate proceeding. Comments on the second draft were due on March 31, 1977. Comments were received from seven Federal agencies, four state organizations, seven companies, including the applicants, and five private or professional individuals or groups.

The terms and conditions are divided into two parts: General, Environmental and Technical. We shall here address only the General terms and conditions. The Environmental and Technical terms are attached as illustrative. It will be far preferable to complete the environmental and technical terms when a route and sponsor are selected. The potential problems can be more precisely identified and the appropriateness of particular requirements can be better assessed. Almost all respondents to the March 10, 1977, draft state that it would be "premature" to issue definitive terms and conditions now. 1/ We agree.

The terms and conditions that we establish will apply to the construction and operation of the pipeline after the applicant is chosen and accepts the certificate. There is no necessity for stating the obvious, but we shall attempt to be as specific as possible concerning the conditions we now deem necessary. We fully appreciate that subsequent consideration of the chosen applicant may require substantial modification.

There are, however, two broad issues that must be resolved. First, whether these terms and conditions should be imposed upon the related sections of pipeline that will be constructed in the lower 48 states. Northern Border and PGT (Pacific Gas Transmission) argue that the terms were inspired by construction in the fragile Arctic environment, and that such extensive terms and conditions have not heretofore been imposed upon certificates for the construction of pipelines in the lower 48 states.

Certainly many of the terms are inherently applicable only in the far northern areas. Many others simply describe sound construction practice that should be observed in all locations. Further review and comments are required before a final decision can be made.

1/ E.g., State of Alaska, Arctic, Environmental Intervenors, Federal Energy Administration, Tennessee Gas Pipeline.

Second, how shall the terms and conditions be enforced? Section 7(a)(5) of the Alaska Natural Gas Transportation Act provides for an office of Federal inspector to monitor the construction of the transportation system. The Federal inspector is not empowered to enforce the terms and conditions imposed by other Federal agencies. The draft terms suggested a division of responsibility between two lead agencies, the Department of the Interior and the Federal Power Commission. The former would have primary responsibility for enforcement over federal lands and the latter over non-federal land, at least to the extent there is a federal interest. Of course, it would be highly desirable for all federal right-of-way grantors to agree upon common protective terms and conditions and vest enforcement authority in the Secretary of the Interior or other single entity. We do not comment upon the extent to which that approach could be achieved under current law.

The Federal Power Commission, of course, has primary responsibility to enforce the terms and conditions included in the certificate of public convenience and necessity. We believe that it will be desirable to vest in the Secretary of the Interior the enforcement of those terms and conditions during the construction period with respect to Federal lands. With respect to non-federal lands, we have not determined the precise form of the enforcement authority. It is possible that it will be necessary, for administrative convenience, to delegate some or all FPC enforcement responsibility to a person, described in the following as an "Authorized Officer", but if so, an absolute right of appeal to the Commission and an expedited process will also be required since in the final analysis the responsibility rests in the Commission.

DRAFT GENERAL AND ENVIRONMENTAL AND TECHNICAL TERMS AND CONDITIONS

General

1. It is the objective of the Commission in proposing these terms and conditions to insure that any system that brings natural gas from Alaska to the lower 48 states shall be designed, constructed and operated in a manner consistent with the goals of the National Environmental Policy Act and consistent with an expectation that the system would provide reliable service to the consumer.

   The location, design, and standards of the construction, operation, and maintenance of the pipeline or LNG systems shall be designed to prevent physical failure from any cause including but not limited to the following:

   a) Seismic and tectonic earth activities, including earthquakes and volcanos.

   b) Sea waves from any cause.

   c) Mass earth movements including, but not limited to, land and snow slides and subsidence.

   d) Differential frost heaving and settling in both permafrost and nonpermafrost areas.

   e) Soil characteristics.

   f) Erosion or stream and gully scour.

   g) Bridges carrying the pipeline over streams.

   h) Impact of the temperature of the pipeline and its contents on the temperature of nearby pipelines and their contents.

   i) Buoyancy.

   j) Pipe and pipe welding specifications.

k) Compressors, meters, valves, and other related facility specifications.

l) LNG plant facilities, cryogenic pipelines, and cryogenic tankers.

m) Vandalism.

n) Excavation on or adjacent to the right-of-way.

o) Inadequate corrosion control.

p) Inadequate communications systems.

q) Glacier surges.

r) Overpressure or other malfunction of safety and control devices.

2. Wherever feasible, as determined by the Authorized Officer, actions which an applicant has indicated, in its application or amended applications to the FPC and/or USDI and subsequent correspondence, would be taken to mitigate, reduce or avoid environmental damage shall be followed in construction, operation, maintenance and termination of the natural gas transportation system. Subsequent correspondence includes but is not limited to the following:

   a) Environmental impact assessments and evaluations prepared by or on behalf of the applicant.

   b) Responses to questions from the FPC or USDI.

   c) Comments made by or on behalf of the applicant on Draft Environmental Impact Statements.

   d) Testimony or exhibits introduced by or on behalf of the applicant at hearings or public meetings regarding the transportation of Alaskan natural gas, including all testimony, exhibits, arguments and briefs introduced by or on behalf of the applicants in the proceedings before the FPC in the case entitled "El Paso Alaska Company, et al." (Docket No. CP75-96 et al.)

Prior to issuance of the FPC certificate and USDI Right-of-Way, these mitigating measures will be identified.

As used in these Terms and Conditions, the term "Authorized Officer" means the agency or representative thereof that has the responsibility for enforcement of a term or condition.

3. The Environmental and Technical Terms and Conditions shall be given priority in routing, construction, operation, maintenance, and termination of the project. Strict compliance with these terms and conditions shall be observed absent a documented showing by the applicant that the conditions are impossible to comply with under the circumstances or that compliance would not avoid or substantially mitigate environmental damage, in which case the Authorized Officer may waive or modify such conditions. Before the Authorized Officer shall approve a request for such a waiver or modification, he shall evaluate the request and accompanying analysis and make a written finding that the request is justified. In making these evaluations and findings, the Authorized Officer shall consider the opinions and judgment of individuals, either on his staff or under contract, having knowledge and expertise in engineering, environmental and other conditions pertinent to the requested waiver or modification of the term and condition. The Environmental Protection Agency will also assist the Authorized Officer or his designated representatives by establishing acceptable criteria for maximum protection of critical environmental areas. If such a request affects a term or condition suggested by another Federal agency and/or its laws or regulations, the initiating agency will be consulted in the review process. The Federal Inspector (see Section 16) shall be advised of any waivers or modifications approved by the Authorized Officer. Compliance shall not in any manner be waived or modified merely on a showing of possible increase in cost or possible short-term delay.

4. The Authorized Officer may at any time order the temporary suspension of any or all construction, operation, maintenance or termination activities of the applicant, their agents, employees, contractors or subcontractors in connection with the pipeline system, if in the judgment of the Authorized Officer, an immediate temporary suspension of such activities is necessary to protect public health or safety; to prevent immediate, serious, substantial and irreparable harm or damage to the environment; or if the applicant is refusing, has failed or refused to comply with any provision of the terms and conditions, provided that the suspension shall apply only to that portion of the construction activity directly affected by the threat or by the particular breach of a term or condition.

5. In addition to the other means of enforcing compliance with the terms and conditions of the Certificate of Public Convenience and Necessity and the Rights-of-Way issued under the authority of the Mineral Leasing Act, the Authorized Officers of the FPC and USDI, respectively, shall, during pipeline construction, prepare and make available to interested persons, including the Federal Inspector and the media, a biweekly activity report which shall include but not be limited to a listing of each violation of any term or condition. This report shall identify the following information for each violation:

a) Term and condition violated.

b) Geographic location of the violation.

c) Date and time violation was discovered by the Authorized Officer or his representative and method of discovery.

d) Action taken by the Authorized Officer or his representative following discovery of the violation, including the date and time the applicant or his representative was advised the violation.

e) Action taken by the applicant to correct violation.

f) Date correction of the violation was completed or whether corrective action is still under way.

This biweekly report shall be prepared and made available to the public no later than 5 working days following the end of the period which it covers.

Environmental and Technical Terms and Conditions

1. The applicant shall prepare a continuing technical environmental briefing program for supervisory and managerial personnel of the applicant and its agents, contractors and subcontractors. Briefings will be conducted by environmental experts from Federal, state, and local agencies, as well as from the applicant, for training, problem solving, and exchange of ideas.

2. An environmental training or briefing shall be mandatory for all construction personnel. The applicant shall inform each person working on the project of specific types of environmental concerns which relate to the individual's job. The training program shall be designed and administered by qualified instructors experienced in each pertinent field of study, and every available method shall be employed to see that the project workers understand and use the techniques necessary to preserve archaeological, geological, and biological resources. The program shall be coordinated with the technical environmental briefing program.

3. The applicant shall identify approved clearing boundaries on the ground for each construction segment prior to clearing operations. All timber and other vegetation outside clearing boundaries and all blazed, painted or posted trees which are on or mark clearing boundaries are reserved from cutting and removal, with the exception of danger trees or snags designated. Prior to clearing operations, the applicant shall notify the Authorized Officer of the amount of merchantable timber, if any, which will be cut, removed or destroyed in the construction and maintenance of the pipeline system and shall pay the United States or other owner (state or private), in advance, such sum as the Authorized Officer determines to be the stumpage value of the timber to be cut, removed or destroyed. All trees, snags, and other woody material cut in connection with clearing operations shall be cut so that the resulting stumps shall not be higher than 6 inches measured from the ground on the uphill side and shall be felled into the area within the clearing boundaries and away from watercourses. Hand clearing

shall be used in areas where the Authorized Officer determines that heavy equipment would be detrimental to existing conditions. All debris resulting from clearing operations and construction that may block streamflow, delay fish passage, contribute to flood damage, or result in streambed scour or erosion shall be removed.

Logs shall not be skidded or yarded across any stream without the written approval of the Authorized Officer. No log landing shall be located within 300 feet of any watercourse. All slash shall be disposed of in construction pads or access roads unless otherwise directed in writing by the Authorized Officer.

4. Material extraction sites have proven to be the greatest sources of environmental impact to fish streams associated with pipeline construction. With this in mind, the following guidelines shall be adopted concerning such sites:

    a) Specific locations and quantities of borrow required should be identified as soon as possible. An estimate of gravel requirements on a mile-by-mile basis should be made, assuming a realistic final design.

    b) New borrow pits should not be located at areas of topographic prominence or at other highly visible sites unless no feasible alternative exists.

    c) No gravel or other material shall be removed from beneath the surface of any body of water or from the beds of overflow channels within active floodplains.

    d) Material sites shall not be located within 300 feet of the vegetated bank of a stream or lake.

    e) Water quality shall not be degraded to the detriment of aquatic life as a result of construction, operation, or maintenance. The applicant shall comply with Federal or state water quality regulations, whichever are more stringent.

f) At no time shall a material site be allowed to block a stream or tidal flow or prohibit fish passage.

g) No gravel extraction equipment or other vehicles shall be allowed to enter or operate within flowing streams or other waters.

h) Any streambank or shoreline area on which the vegetative cover is disturbed shall be replanted with trees, brush or other vegetation similar to the type and concentration which exists near the water in the general vicinity of the material site.

i) Disposal sites from debris resulting from the use of material sites shall be placed above the reach of floodwaters.

j) No gravel washing operations shall take place within the active floodplain of any stream. Sediments resulting from washing operations shall not be allowed to enter the active floodplain at any time.

k) No excavated materials shall be stockpiled or stored within the active floodplain.

l) No vehicle or equipment maintenance such as fueling, overhaul, washing, or storage shall be conducted within the confines of material sites associated with streams or other bodies of water.

5. Communication facilities shall be designed, located, and constructed to minimize impact on birds, aesthetics, aircraft operations, and other communication facilities.

6. To the maximum extent practicable, existing roads, improvements, and facilities shall be used rather than constructing new facilities and improvements.

7. All necessary roads and work pads, including snow roads and snow pads constructed either on or off the pipeline right-of-way, shall be located and designed to standards

commensurate with expected use, shall minimize environmental damage, shall minimize interference with normal water flow, and shall not cause excessive ponding of water. Any drainage structure constructed shall be adequate to accommodate a 50-year flood, in accordance with the criteria established by the AASHO, and shall not interfere with the passage of fish. Snow roads and work pads, if used, shall be constructed to prevent disturbance, destruction, or damage to underlying vegetation.

8. The applicant shall review Alyeska's streamflow data for any permafrost areas which may be encountered by the applicant and, where the data or the resulting design have been found to be inadequate, shall conduct further studies to allow the design of adequate culverts. All culverts not an integral part of the permanent haul road shall be installed only temporarily. Immediately after construction, these temporary culverts shall be removed and the stream channels restored to their original configurations. Measures that would minimize the problems of frozen culverts and resulting aufeis shall be used. Techniques should be developed to keep the culverts open all winter, or at least thaw them open before fish migrations begin in the spring. Other types of drainage structures might be considered where aufeis is a particular problem.

9. To reduce siltation, streams with silt bottoms shall not be excavated until immediately prior to pipelaying.

10. The contract for construction shall include provisions to protect the completed erosion control measures from damage by equipment and pedestrian traffic, concentrated runoff, and other controllable causes. Contractors shall be required to repair any such damage which may occur while the contractor is in the areas where revegetation is in process.

11. Every effort shall be made to avoid damage to wetlands during construction. If a marsh or bog is drained, it shall be restored as soon as possible.

12. The following water availability standards shall be applied:

a) The volume of water withdrawn from lakes shall not exceed 5 percent of the total volume of water available.

b) During development of sources and during water withdrawal, each location with known populations of spawning or overwintering fish shall be monitored by a fisheries biologist familiar with lakes and springs of the particular areas.

c) Springs known to support fish populations shall not be developed as sources of water if suitable alternative sources are available.

d) When springs are developed as water sources, damage to the aquatic environment shall be minimized by:

i. avoiding rechannelization of natural spring channels or removing subterranean accesses of such springs;

ii. using sumps in the gravel downstream toward the aufeis and away from the spring orifice;

iii. providing suitable barriers or screens to prevent fish from entering sumps or collection ponds; and

iv. avoiding long lengths of access road parallel to spring channels.

13. Areas disturbed by construction activities should be revegetated. Analysis of experimental data at the Sans Sault test facility (65° 45'N, 128° 49'W) indicates that it is possible to grow sufficient plant cover over

the pipeline in the northern boreal forest to provide some insulation to permafrost. However, the results from the test site do not necessarily represent the amount of plant cover that would be obtained during the actual full-scale operation to revegetate the pipeline. They do show that a good plant cover is possible in the boreal forest region and that further research could define procedures to ensure pipeline revegetation. The revegetation measures shall include the following:

a) All areas disturbed by the project shall be seeded with an appropriate combination of forage grasses and, if available, native grasses and fertilized in sufficient amounts to insure rapid growth and dense ground cover. In those areas such as the tundra, where seeding with grass would not be effective, stripping and seeding of the organic mat shall be used.

b) On slopes greater than 10°, erosion control mats shall be staked down to hold the soil until the grass germinates and the seedlings become firmly established. Shrub cuttings shall be used to stake the erosion control mats in place. The cuttings could take root and further aid in soil stabilization.

c) Additional fertilizer shall be applied in the second and third growing seasons if necessary to maintain growth of the grasses; in those areas where regrowth is poor, grass seed shall be reapplied.

d) Further research shall be conducted to ascertain techniques to ensure successful revegetation in all areas of the pipeline right-of-way.

e) The applicant shall evaluate the restoration and revegetation procedures of the Alyeska pipeline project and incorporate the best of those into the proposed project.

14. During negotiations for rights-of-way purchase, owners of agricultural lands shall be apprised of their right to require reseeding.

15. Studies on the major mammals, particularly grizzly bear, moose and caribou, shall be continued by the applicant for 5 years beyond the close of construction to determine whether pipeline construction has had or would have significant impact on the reproduction and distribution of these species.

16. Construction of the proposed pipeline shall be conducted in such a manner that extensive lengths of open trench or unburied pipe will not injure animals or interfere significantly with their passage across the right-of-way.

17. To alleviate part of the impact of human-wildlife interaction, work camps, waste disposal areas, compressor stations and storage areas shall be supplied with animal-proof fences. All gates shall be closed when not in use. Under no circumstances shall any personnel be allowed to feed animals. The applicant shall cooperate with local government agencies to live-trap and transport dangerous nuisance animals to safe areas as soon as their intention to linger becomes evident.

18. Aircraft flights shall be strictly controlled to minimize harassment of wildlife. Since Dall sheep are particularly sensitive to helicopter activity, overflights of their mineral licks and lambing areas shall be strictly forbidden while they are in use. Helicopter flights shall not be allowed to deviate from the centerline of the proposed right-of-way when crossing Dall sheep habitats.

19. Aircraft flights by the applicant and its agents, contractors, and employees during construction, operation, and maintenance of the pipeline system at horizontal distances greater than 1 mile measured diagonally to the center line of the pipeline shall be at vertical elevations not less than 1,000 feet above the ground surface, except during take off and landings and emergencies which involve the continued operation of the aircraft.

20. The successful applicant shall employ vegetation and wildlife specialists to review the final pipeline route and/or LNG plant for sensitive areas and follow the recommendations of these experts following concurrence by the Authorized Officer.

21. Some stream crossings for the Alcan and El Paso proposals are within or directly upstream from spawning beds for several species of salmonid fishes. Buried pipeline crossings would cause significant impact no matter when the construction took place. Other fish streams that flow through deeply incised channels have proven environmentally sensitive to impact because of bank instability. Aerial crossings shall be considered for such rivers and creeks.

22. Through its agents, contractors, and subcontractors, the applicant shall not allow its employees to camp, fish, shoot, or hunt within 5 miles of any construction-related activity. Upon completion of construction, the applicant shall post the right-of-way to prohibit such activities within a distance from the right-of-way, compressor station sites, and other aboveground facilities determined by agreement between the applicant and the appropriate Federal and state officials.

23. River crossings during the winter or spring, especially in grayling streams, shall be planned so that no obstacles to fish passage remain in the floodplain at breakup. Ice bridges shall be deliberately broken up as soon as possible to prevent them from blocking fish migrations upstream in the spring.

24. The effects of major oil or other spills on a freshwater habitat are generally unknown. Should such a spill occur during the proposed construction, the Authorized Officer shall conduct a follow-up study to determine the effects on fish, wildlife and their habitats and attempt to update existing techniques for measuring and mitigating impacts from spills occurring under arctic conditions.

25. No fuel oil or gasoline lines shall be buried in gravel work pads. If fuel lines must be placed underground, they shall be encased in easily inspected oil-proof conduits to facilitate leak detection and to prevent contamination of groundwater.

26. Fuel storage tanks shall have an accurate volume gauge, and the fuel lines entering and leaving the tank shall be equipped with accurate meters. Each component of the fuel storage system shall be isolated by valves to facilitate leak detection and repair. Above all, an accurate record of additions and withdrawals from fuel tanks shall be kept and frequently compared with inventories of the tank volumes to insure prompt detection of leaks.

27. The applicant shall institute spill prevention, containment and control plans for all areas where oil, oil-derived substances, and hazardous materials are stored. Storage tanks for fuel and other toxic substances shall be placed within bermed enclosures having linings impervious to the substance in storage. The bermed areas shall be large enough to contain at least 110 percent of the stored volumes, since snow or rain may accumulate within the bermed area.

28. Personnel shall be actively trained in handling, storage, use, spill containment, and cleanup of toxic substances. Training shall include actual demonstrations of these procedures for all construction personnel.

29. When pumping spilled fuel or a fuel/water mixture, impeller pumps shall not be used because they tend to emulsify liquids. Vacuum, positive displacement, or diaphragm pumps shall be used instead. A means of effectively treating and disposing of snow/oil mixtures should be developed.

30. The applicant shall begin as soon as possible to work with the Environmental Protection Agency and the State of Alaska to establish approved disposal areas for waste products. Temporary storage containers for toxic wastes must be developed to replace the inadequate containers frequently used during pipeline construction. Fifty-five gallon fuel drums are not suitable for temporary storage because they are thin-walled, easily corroded, and poorly sealed. All sanitary and solid wastes generated at the work camps must be treated and discharged so as not to violate existing water quality standards. All solid wastes must be disposed by sanitary landfill or other acceptable means.

31. When establishing new work camps and reopening old camps, a buffer zone of at least 300 feet of fenced, undisturbed land shall be maintained between the camp boundaries and all bodies of water to insure spill containment and prevent unnecessary disturbances of riparian habitats. Special precautions or restrictions shall be applied to refueling operations and handling of other toxic substances within 300 feet of active floodplains. Storage of toxic substances, even temporarily, shall not be allowed in active floodplains. If possible, idle equipment shall be parked away from lakes and streams to avoid contamination from fuel and lubricant leaks.

32. The applicant shall employ adequate and approved technology for reducing continuous and maximum noise levels at compressor stations.

33. Noise levels at the property boundary of compressor stations shall not exceed the following levels:

    a) Continuous noise level of 55 dB(A)

    b) Maximum noise level of 80 dB(A), not to exceed 5 minutes

Increases of pure-tone characteristics shall be prohibited.

34. The periodic scheduled venting (blowdowns) of the gas pipelines and compressor stations shall be accomplished so as to avoid unnecessary disturbance of wildlife, such as caribou calving and bird nesting. Blowdown silencers shall be installed near sensitive wildlife concentrations to mitigate the impact of unscheduled blowdowns. Blowdowns shall not be scheduled during periods and at the locations specified by the Authorized Officer.

35. All construction, testing, operation, and maintenance, especially blasting, near existing oil pipelines, natural gas pipelines, oil and natural gas storage facilities, and any other improvement or facility of any type (public or private) shall be conducted to prevent damage to the improvement or facility and to minimize interference with its normal operation.

36. Where practicable, impact to fish from blasting shall be lessened by scheduling work close to water bodies during the least sensitive times of the year, using the smallest possible explosive charges, and appropriately sequencing the ignition of multiple charges to minimize the amplitude of shock waves. Additional studies are needed to better predict impact from blasting under the variable conditions in Alaska and Canada.

37. Where ice fog resulting from construction, operation, and maintenance of the pipeline and/or LNG facility constitutes a hazard to air navigation, communication, or public health and safety, the applicant shall be required to provide mitigating measures to eliminate the hazard or to devise a system to dissipate or eliminate the ice fog.

38. Pursuant to the National Historic Preservation Act of 1966, as amended, the Archaeological and Historical Preservation Act of 1974, and the Advisory Council for Historic Preservation's Procedures for the Protection of Historic and Cultural Resources, 36 CFR Part 500, the applicant shall initiate a cultural resource survey and salvage program to minimize the loss of cultural

resources (historic and prehistoric sites, structures and objects) caused by pipeline-related activities. The applicant shall allocate sufficient funds for such a program and allow a reasonable period of time for adequate surveys, preservation, and salvage.

The surveys shall cover the pipeline right-of-way, including all areas that would be affected by construction of the pipeline and related facilities. The surveys and salvage shall employ the services of competent archaeologists, historians, and other relevant specialists and shall be made in full cooperation with the appropriate State Historic Preservation Officers (SHPO), officials of the Department of the Interior and the Advisory Council on Historic Preservation. Construction personnel shall be instructed on the importance and identification of cultural resources. The survey and salvage program shall include the following:

a) Prior to determining final alignments and locations of project-related facilities and in consultation with the appropriate SHPO's, the applicant shall conduct cultural resource surveys.

b) Before construction of the pipeline and related facilities, the applicant shall avoid and/or mitigate adverse impacts on significant sites and areas of cultural resource concentration.

c) During construction of the pipeline, support facilities, borrow areas, etc., archaeologists shall accompany construction crews through areas where significant archaeological sites are probable to identify sites previously overlooked and to recover cultural remains discovered during construction.

d) Artifacts and other materials removed from sites on Federal lands shall remain the property of the Federal Government;

artifacts and other materials removed from non-Federal lands shall be disposed of after analysis and as agreed by the survey coordinator and the landowner(s) under applicable state laws.

e) Reports should be made periodically to appropriate state and Federal agencies on the results of all operations, and a final program report should be issued at the completion of the entire program.

f) Compliance with the pertinent cultural resource preservation statutes and regulations will entail extensive cooperation and coordination among the various state and Federal jurisdictions along the pipeline route. The entire sequence of work, therefore, shall be administered by the Secretary of the Interior, as provided by the Archaeological and Historical Preservation Act of 1974. The Secretary shall administer the survey/salvage sequence to assure quality control, proper phasing of investigations with construction schedules, and procedural compliance with these stipulations and other pertinent statutes and regulations.

39. In all aspects of construction, operation, and maintenance of the pipeline and/or LNG plant system, the operation of wheeled, tracked or low ground pressure vehicles off roads, or work pads shall be held to a minimum during periods when such vehicle operations will damage the vegetation, soil or other resources.

40. Survey markers of any type shall not be disturbed. If it is necessary to disturb survey markers, they shall be replaced by competent surveyors.

41. Wildfire prevention, presuppression, and suppression plans shall be prepared, updated annually, and operated for each segment of pipeline construction. Following construction, such equipment shall be installed and

readily accessible at compressor stations and at maintenance/storage sites.

42. Where terrain and proximity to the Alyeska oil pipeline would seriously hinder or prevent future looping of the gas pipeline, e.g., in Atigun Pass, the applicant shall utilize the largest diameter of pipe compatible with safety requirements of the design system so that future expansion of the pipeline system will not require extensive deviations from the Alyeska right-of-way and create additional environmental impact.

43. The pipeline and/or LNG plant system shall be designed, where technically feasible, by appropriate application of modern state-of-the-art seismic design to prevent any gas leakage from the effects (including seismic shaking, ground deformation and earthquake-induced mass movements) of earthquakes. Any LNG facilities associated with the selected route shall be designed in accordance with Nuclear Regulatory Commission standards for nuclear powerplant facilities. The distribution of design Richter magnitude earthquakes for the pipeline route and/or LNG plant will be determined by the Commission in the final terms and conditions governing the selected project.

Where such design is not technically feasible, as determined by the Authorized Officer, the potential damage shall be minimized by special design provisions that shall include, but shall not be limited to: (1) a network of ground-motion detectors that continuously monitor, record and instantaneously signal ground motion in the vicinity of the pipeline reaching the Operational Design Level (highest level that would not produce general pipe deformation sufficient to limit operations); the critical levels of ground motion shall be approved in writing by the Authorized Officer; (2) rapid programmed shutdown and prompt close inspection of system integrity if ground motion reaches the Operational Design Level; and (3) a special contingency plan for natural gas leaks for each such seismically hazardous area. This plan shall specifically consider expected field conditions in the particular area following a destructive earthquake.

The applicant shall satisfy the Authorized Officer that recognizable or reasonably inferred faults or fault zones along the alignment within that segment have been identified and delineated and that the risks from fault movement and ground deformation have been adequately assessed and provided for in the design of the pipeline for that segment. Evaluation of said risk shall be based on geologic, geomorphic, geodetic, seismic, and other appropriate scientific evidence of past or present fault behavior and shall be compatible with the design earthquakes tabulated above and with observed relationships between earthquake magnitude and extent and amount of deformation and fault slip within the fault zone.

Minimum design criteria for a segment of the pipeline traversing a fault zone that is reasonably interpreted as active, shall be: (1) that the pipeline resist failure resulting in leaks from 2 feet of horizontal and/or vertical displacement in the foundation material anywhere within the fault zone; and (2) that no compressor station be located within the fault zone.

Where the pipeline crosses a fault or lies within a fault zone that is reasonably interpreted as active, the applicant shall monitor crustal deformation in the vicinity of the pipeline. Such monitoring shall include annual geodetic observation of permanent reference marks established on stable ground. These reference marks shall be positioned so as to form closed figures and to provide for detection of relative horizontal and vertical displacements as small as 0.10 ft. across principal individual faults within the fault zone and to provide for monitoring of crustal strain with an absolute error of two parts per million within the fault zone. Further, where annual slip on a fault exceeds 0.10 ft. for 2 successive years, the applicant shall install recording or telemetering slip-meters. Data obtained from the monitoring shall be provided to the Authorized Officer at specified regular intervals throughout the operation of the pipeline. Said data shall be used by the applicants to aid in the initiation of corrective measures to protect the pipeline from failure caused by tectonic deformation that would result in leaks.

44. LNG tanks shall be provided with top and bottom fill line capability to prevent "rollover" conditions caused by potential density variations between incoming LNG and LNG already in the tanks.

45. A density monitoring program which would periodically check the density of LNG flow to the storage tanks shall be implemented to determine the need for top or bottom filling.

46. Adequate spill containment, ditching, and land sloping on the marine trestle and/or on shore shall be provided so that the maximum amount of LNG which could spill if an LNG transfer line failed between the shoreline and the diked tank area would be contained within the applicant's property boundary.

47. Additional thermocouples shall be provided on the tank floor and lower shell of the inner LNG tank to obtain more comprehensive data on the thermal stresses imposed during cooldown.

48. The internal storage tank LNG temperature probe shall be located so that the accuracy of its data sendout will not be thermally influenced by fluid circulation within the tank or by other structural members.

49. Linear movement indicators between the inner and outer tank shells shall be installed on the proposed LNG storage tanks to provide data on the relative position of the inner and outer shells. In addition, the applicant shall install anchor bolts on the outer tank to secure it to the foundation.

50. Primary and backup signal lines installed for all instrumentation and control systems at the LNG terminal shall be routed separately to each such system to avoid simultaneous damage if an accident occurs.

51. The final design plans for the proposed LNG terminal should be submitted to the Commission for review prior to commencement of the construction of the terminal.

52. If the LNG terminal is approved for operation, the Commission shall require operational reports semiannually, within 45 days after each period ending December 31 and June 30, describing facility operations for the period covered, noting only abnormal operating experiences or behavior. Abnormalities shall include, but not be limited to, rollover, geysering, cold spots on the tank, significant equipment malfunctions or failures, nonscheduled maintenance or repair (and reasons therefor), relative movement of the inner vessel after each cooldown and following local seismic activity, vapor or liquid releases, negative pressures (vacuum) within the storage tank, and higher than predicted boil-off rates. The technical information supplied by the applicant shall be submitted in a form acceptable to the Commission and shall be in sufficient detail to allow a complete understanding of such events consistent with the existing state-of-the-art or knowledge. If an abnormality endangers the facility or operating personnel, the Commission shall be notified immediately.

COMMENTS IN REFERENCE TO STAFF-PROPOSED GENERAL TERMS AND CONDITIONS THAT WERE REJECTED, RESERVED, OR MODIFIED

Proposed Term

1. The general route and capability of the system will be selected through the procedure established by P.L. 94-586. Following this selection, the exact routing, construction design and standards, operation, and maintenance will be approved by the administering agencies. Throughout these procedures, expeditious completion of the delivery system and reliable natural gas transmission will be balanced against costs and environmental damage. The lawful rights of affected landowners will be preserved in all instances.

Comment

The first sentence restates the obvious. The second sentence is merely descriptive. Neither applies to the construction or operation of the system. The third sentence is too general to be helpful, and provides no real standards for balancing. As to the fourth sentence, no applicant has the power to destroy lawful rights of land owners or other persons.

Proposed Term

2. The applicant will be required to comply with all Federal, state, and local laws, ordinances, and regulations which reflect a sovereign interest, provided such laws are not waived and do not discriminate against either the applicant as a person or the route selected. The provisions of the gas pipeline safety regulations contained in 49 CFR Parts 191 and 192 are to be met by the applicant in the design, construction, testing, operations, maintenance, and inspection of any pipeline segment of the Alaska gas transportation system authorized for the United States. (Sovereign interest is defined as those activities of government applicable and applied to all actions and on all lands within the United States, regardless of ownership.)

Comment

First sentence.
Federal supremacy and pre-emption, and the relationship of state and local laws are subjects far too complex to cover in one sentence. Of course, applicants will be expected to obey applicable laws; among those are all laws that are supported by a legitimate sovereign interests. Laws may not discriminate against applicants any more than other persons. No law "waived" need be obeyed. Determination of applicable law must be made on a case-by-case basis.

Proposed Term

3. The applicant will be required to comply with Federal, state, and local laws, ordinances, and regulations which reflect a publicly owned proprietary interest in land along the selected route to the extent that compliance is practicable, is not waived, and is not enforced in a manner discriminatory toward the applicant as a person or the route selected. (Proprietary interest in land is defined as ownership of title to the land or an interest therein.)

Comment

This proposed condition is not forwarded for essentially the same reason as applies to the first sentence of 2. above. Also, we note that the standard-"reflect a publically-owned proprietary interest in land"-is too vague for identification. Further, laws, if applicable (if waived, they are not "applicable"), should be obeyed whether or not compliance is "practicable."

Proposed Term

4. To the extent applicable because of the physical nature of the land and resources involved, a non-Federal landowner may insist that the easement acquired by the applicant include all or some of the terms and conditions made part of the right-of-way granted by the United States over federally owned lands. The landowner and applicant may agree to include additional terms and conditions in the easement. In negotiations between the landowner and the applicant, terms and conditions to the easement may change and amend the real property interest acquired by the applicant and consequently affect the just compensation paid for the right to construct the pipeline on the property.

Comment

Non-Federal land owners and applicants may agree to any terms or conditions for the easement not otherwise unlawful. If the first sentence is intended to give non-Federal land owners the unilateral ability to impose conditions, we disagree therewith. The standard "to the extent applicable because of the physical natural of the land and resources involved" is exceedingly vague and would inspire litigation. The non-Federal land owner has the protection of general law and we do not believe at present it is appropriate to interfere therewith.

Proposed Term

5. The procedural and other requirements with which the Federal Government must comply under Sections 301 and 302 of P.L. 91-646, the Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970, in the acquisition of real property shall be followed by the applicant in acquiring all real property from non-Federal landowners. In addition, the applicant shall pay non-Federal landowners the incidental and litigation expenses, provided for in Sections 303 and 304, if such payment by the United States would be appropriate in similar circumstances.

Comment

We do not include this condition at this time. There are unresolved issues regarding the applicability of the Federal standards to acquisition of non-Federal land. The law of emminent domain has operated heretofore successfully and we believe that further review and comment is appropriate.

Proposed Term

6. Selection of the route has been made giving full consideration to the several types of Federal land use and resource studies and projects authorized by law. No Federal agency or officer shall delay issuance of any necessary right-of-way or other permit because such a land use, resource, or project study is contemplated, authorized, or underway, or the decision is still pending.

Comment

While without question this provision states a laudable objective, it is a matter over which the applicant has no control. The Federal Power Commission can control only its internal procedures and that can be done without imposing any condition upon an applicant. Finally, Section 9 of the Alaska Natural Gas Transportation Act of 1976 covers this matter.

Comment

7. Proposed General Term No. 7 is more realistically cast as an objective rather than absolute requirement. It appears as No. 1 in the revised draft.

Comment

8. This Proposed Term appears as No. 3 above. We delete the words "or could" that appeared in the fifth line. Any statement that reasonably can be construed as an undertaking by the applicant will be so construed in the enforcement of this condition. Therefore the "indicated (by applicant) . . . would be taken" is broad enough to cover the statements to which an applicant should be held. The determination of feasibility or infeasibility made the the "authorized officer" who was an agent of the Federal Power Commission could be appealed by any party to the Commission and should be given expedited treatment.

Proposed Term

9. Title I of the Mineral Leasing Act, as amended, authorizes the Secretary of the Interior or his delegate(s) (Authorized Officer) to grant the right-of-way permits for crossing all federally owned land. The Act further provides that these rights-of-way will be administered by the agency having jurisdiction over the specific tracts of land crossed. To meet their particular jurisdictional and administrative responsibilities, the affected agencies may designate duly authorized representatives to the Authorized Officer. Before any agency administering these rights-of-way on land under its jurisdiction takes any action, including but not limited to actions authorized by Section 11 of P.L. 94-586, which would delay construction, completion, or initial operation of the natural gas transportation system, increase the cost of construction and/or operation and maintenance, or interrupt operation of the system, the concurrence of the Secretary of the Interior or the Authorized Officer shall be secured.

Comment

The first two sentences merely describe the functions of the Secretary of the Interior in granting rights-of-way across Federal lands. The next three sentences seem to express a desire that the Secretary of the Interior (or Authorized Representative) coordinate the administration of terms and conditions imposed with respect to the Federal lands which the pipeline traverses.

We certainly agree that the administration and enforcement activity with respect to this project should be centralized as much as possible. Uniform standards, uniformly enforced, unquestionably could expedite the construction of the project and maximize environmental mitigation. Of course, the Federal Power Commission has no power to compel other Federal agencies to join in any activity. The President does have such authority. We recommend that he insure the maximum possible degree of consistency in the standards for enforcement of all terms and conditions.

Proposed Term

12. The Authorized Officer may at any time order the temporary suspension of any or all construction, operation, maintenance or termination activities of the applicant, their agents, employees, contractors or subcontractors in connection with the pipeline system, if in the judgment of the Authorized Officer, an immediate temporary suspension of such activities is necessary to protect public health or safety; to prevent immediate, serious, substantial and irreparable harm or damage to the environment; or if the applicant is refusing, has failed or refused to comply with any provision of the terms and conditions.

Comment

Certainly, construction should be terminated whenever there is an imminent threat to public health or safety or of irreparable harm to the environment. The final clause however, is overly broad. Failure to comply with a term or condition should be a basis for termination only of construction activity directly affected by the threat, or by the particular breach of a term or condition.

Proposed Term

13. As required by Section 28(1) of the Mineral Leasing Act, as amended, the applicant will be required to reimburse the United States for costs incurred in processing and administering the necessary rights-of-way and permits on federally owned land. If the FPC and/or other Federal agencies appoint an Authorized Officer, the applicant may be required to reimburse the United States for direct costs incurred in administering and monitoring the construction, operation, and maintenance of the pipeline and related facilities on private land.

Comment

The first sentence merely restates the existing law. Its inclusion could only serve to inform the person encumbered by these terms. Such person would be presumed already to be so informed. As to the second sentence, the FPC can impose fees where the law so provides. We do not believe it proper to attempt to extend such law indirectly.

Proposed Term

15. No action not already approved in project plans which significantly affects the environment or is subject to review or approval by the Authorized Officer shall be taken by the applicant until the action is approved in writing by the Authorized Officer.

Comment

Pursuant to Term 4, the authorized officer would have the power to suspend construction that was causing irreparable harm to the environment. At this time, we do not believe that such a broad restriction as that suggested above would be required. The State of Alaska has suggested the adoption of a "Notice-to-Proceed" mechanism such as was used on the Alyeska line. We shall give further consideration to this issue at a later time.

Proposed Term

16. The duties of the Federal Inspector (either as an individual or as a board) are defined by Section 7(a) (5) of P.L. 94-586 and consist of monitoring, surveillance, information gathering, and reporting. These duties are further defined to specifically exclude any activity or exercise of any authority which may be construed to be direct enforcement of applicable law, regulation, or term or condition of a right-of-way or permit. However, the Federal Inspector is authorized and directed to consult with and advise applicable Authorized Officers, the applicants, and their subcontractors and employees of actions which he has found to be in violation of law, regulations, and terms and conditions of the certificate, right-of-way, or permit. The Federal Inspector shall notify the appropriate agency of possible violations within that agency's jurisdiction or of violations of terms and conditions which that agency has initiated. In addition to his other duties, the Federal Inspector is authorized and directed to investigate, report on and advise the applicant of complaints received from non-Federal landowners that the applicant has or is violating the terms and conditions of the easement acquired by the applicant for crossing the landowner's property. The Federal Inspector is also authorized to establish with all states traversed by the Alaska natural gas transportation system joint monitoring and surveillance agreements, similar in purpose, intent, and scope to the agreement authorized by Section 7(a) (5) of P.L. 94-586 with the State of Alaska.

Comment

This basically is merely descriptive of the Office of the Federal Inspector. The third sentence purports to place on the Office a duty of notification. Albeit a reasonable duty that is not within the jurisdiction of an applicant or the Federal Power Commission.