Working Group Report

National Economic Impact

of

Alaskan Natural Gas Transportation Systems

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Federal Energy Administration
Department of Commerce
Department of Interior
Department of Labor

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Task Force on Alaskan Natural Gas Transportation Systems

National Economic Benefits

The FPC Recommendation to the President compared the three alternative systems against two criteria:

- o Net national economic benefits--a measure of the discounted benefits and costs of the projects.
- o Cost of service--a measure of the cost of delivering natural gas to consumers (including an assumed wellhead price of $1.00 per MCF).

All systems had substantial net benefits (from $5.8 billion to $8.2 billion) and a cost of service that was judged competitive with alternate fuels (a high of $2.26 per MCF).

Alcan and Arctic had the highest net benefits and a lower cost of service than El Paso.

This Task Force report examines the sensitivity of the FPC findings to different discount rates, cost overruns, and schedule delays and calculates new employment impacts.

The new findings using the expected values for overruns and delays indicate that all of the systems still have positive net benefits ($3.3 billion to $4.8 billion) although reduced from the FPC levels and have increased costs of service (a high of $2.50 per MCF) which are still competitive with alternative fuels.

Alcan has the highest benefits with El Paso second. The rank changes because El Paso was judged to have a lower likelihood of substantial overruns. El Paso remains with the highest cost of service.

A sensitivity analysis shows that net benefits will be reduced to zero if either of the following occurs (assuming a discount rate of 10% and constant real gas prices):

- a construction delay greater than four years
- construction cost increases of more than 100%
- a reduction in throughput from 2.4 BCFD to less than 1.2 BCFD.

El Paso has claimed large relative employment impacts for the El Paso system (730,000 person years versus 235,000 person years for Alcan). This report finds that the relative differences between systems are considerably smaller (271,000 person years for El Paso versus 240,000 person years for Alcan).

Table A

The Effect on NNEB of Expected Project Cost Overrun and Schedule Delay[3]
(Millions of 1975 dollars)

	Arctic			El Paso			Alcan		
	13%	10%	6%	13%	10%	6%	13%	10%	6%
Value of gas[2]	7297	11056	20557	7076	10551	19167	7856	11649	21013
less:									
Field gathering & conditioning	858	961	1124	858	961	1124	969	1057	1192
Field O&M	22	34	64	25	37	67	24	37	67
Transportation Facilities	4762	5503	6733	3780	4361	5318	4113	4701	5666
Working Capital	13	15	19	28	34	43	23	28	36
System O&M	166	251	469	538	802	1458	169	253	463
U.S. Other Taxes	110	154	250	325	449	716	172	235	368
Canadian Income Taxes	503	775	1440	0	0	0	228	352	657
Canadian Other Taxes	13	53	92	0	0	0	107	162	299
NNEB	827	3311	10366	1522	3908	10441	2051	4825	12265
(Base Case)[1]	4125	7298	15379	3056	5800	12859	3968	7113	14974

1/ Working group base case as shown in Table IV-1.

2/ Assumes no growth in unit value of natural gas.

3/ Derived from computations detailed in the report of the Cost Overrun task force.

Table B

Estimates of Delivered Cost - National Average (per million BTU in 1975 dollars including an illustrative price of $1.00 at Prudhoe Bay and for gas fuel)

	Twenty Year Simple Average 1/	Leveled Average 1/
Arctic Gas 2/		
Applicant Costs 5/	1.72	1.87
Expected Value Case	2.09	2.32
Worst Case	3.11	3.61
Alcan 3/		
Applicant Costs 5/	1.79	1.95
Expected Value Case	2.09	2.33
Worst Case	2.96	3.39
El Paso 4/		
Applicant Costs 5/	2.09	2.26
Expected Value Case	2.26	2.50
Worst Case	2.78	3.14

1/ Average calculated over first 20 years of flow including years of partial flow except for "applicant cost" case. Here first 20 years of full flow was used.

2/ Flows: Prudhoe Bay - 2.4 BCFD, Mackenzie Delta - 1.00 BCFD.

3/ Flow: Prudhoe Bay - 2.4 BCFD.

4/ Flow: Prudhoe Bay 2.36 BCFD.

5/ Taken from submittals to the Federal Power Commission.

Table C

Total Jobs Generated by Direct and Indirect Expenditures

	El Paso	Alcan	Arctic
1977-78	1,850	1,700	0
1979	7,150	17,450	21,350
1980	80,600	65,500	31,250
1981	100,950	92,250	62,850
1982	64,550	59,000	67,200
1983	15,550	150	22,150
1984-93	0	4,400	5,950
	270,650	240,450	210,750

NATIONAL ECONOMIC IMPACT OF THE ALASKAN NATURAL GAS TRANSPORTATION SYSTEMS

I. INTRODUCTION

This interagency task force report will evaluate the national economic impact of the three alternative Alaskan natural gas transportation systems (Arctic, Alcan, and El Paso) as presented by the Federal Power Commission (FPC) in its Recommendation to the President (May 1, 1977). This report has been written to comply with Section 6(a)(vi) of the Alaskan Natural Gas Transportation Act of 1976.

The FPC Recommendation to the President assesses the relative economics of alternative Alaskan natural gas pipeline routes along two dimensions. The first dimension is net national economic benefits (NNEB) and the second is the cost of service to the consumer. The major controversies surrounding these two measures are both theoretical and empirical.

The NNEB approach asks what is the value of the benefits expected to flow to the nation as a result of the alternative proposals and what are the costs associated with those benefits. It considers the flow of the costs and benefits over a period of time and asks what is the net present value of future benefits and costs. Theoretically, the costs and benefits are those to the nation and as such should include social benefits and social costs. To the extent that social costs and benefits differ from private costs and benefits, the NNEB approach should reflect this.

The cost of service concept is used in public utility rate regulation procedures. It implies more or less standard procedures for depreciating investments over the life of a project and allocating other necessary expenses. It includes all those expenses which are considered acceptable in rate making procedures and which must be paid by consumers.

Macroeconomic impacts, only briefly covered by the FPC report, are also discussed in this report. The macroeconomic impact analysis is commonly used to estimate the economic effects of a major policy decision. This type of analysis includes changes in employment, consumer prices, wholesale prices, and gross national product.

There are ongoing debates about the proper definitions of inputs to the analyses. Within the NNEB approach, there are differing positions concerning the level of the discount rate, whether to include or exclude certain taxes paid to Canada and U.S. taxes other than income taxes, the inclusion of national independence benefits or employment, balance-of-payments, or other macroeconomic impacts. With regards to cost of service, there are differing views on a number of issues including the proper time horizon over which to calculate the costs and the appropriate financial assumptions.

Even were it possible to agree on what costs and benefits should be included and how they should be discounted, the question of reliability in the numbers has not been resolved. The subject of cost estimates, cost overruns, financing, and marketability of Alaskan natural gas are treated in other task force reports and are not analyzed separately here. This report will attempt to incorporate the most reasonable assumptions and cost estimates to estimate the national economic impact.

This report contains five sections submitted by various members of the task force. The first section reviews the evidence and positions of interested parties on the NNEB. A thorough discussion of the FPC recommendations, NNEB, and cost of service calculations is presented in the second section. The third section gives a sensitivity analysis of the NNEB under different assumptions. The short-term employment impacts of the three systems are discussed in the fourth section. The fifth section describes the long-term macroeconomic impacts of an Alaskan natural gas transportation system versus no transportation system. This study discusses the impacts on the gross national product, consumer price index, wholesale price index for energy, and unemployment rate. A final section is included which summarizes the major findings of the task force.

II. A REVIEW OF THE EVIDENCE AND POSITIONS OF INTERESTED PARTIES

Thus far, at least six cost-benefit analyses have been made of the alternative proposals for transportation of Alaska natural gas. A summary of these six analyses is presented in Table II-1. The first cost-benefit analysis was conducted by the Department of the Interior as part of the December 1975 report to Congress required by the Trans-Alaska Pipeline Authorization Act of 1973.[1] Later, the Federal Power Commission staff included a cost-benefit analysis as part of their Environmental Impact Statement. This analysis was based primarily on that conducted by Interior. Later, Arctic Gas and El Paso submitted cost-benefit analyses at the FPC hearings. The Alcan Pipeline Company did not prepare a cost-benefit analysis and argued that such analyses should not "form the basis for a comparative decision in this case." In its recommendation to the President, the FPC also included a cost-benefit analysis of the alternative systems. In response to criticisms made by the applicants at the FPC hearings about the methodology and results of the cost-estimating techniques used in the December 1975 Interior study and to include an analysis of the Alcan 48" proposal, consultants to the Department of the Interior have revised the earlier estimates.[2]

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[1] U.S. Department of the Interior, Alaskan Natural Gas Transportation System: A Report to the Congress Pursuant to PL 93-153, December 1975.

This was prepared by an interagency study team using data supplied by the Aerospace Corporation (a non-profit Federal Contract Research Center) and subcontractors in each of the major technical areas. A companion document is:

The Aerospace Corporation, Alaskan Natural Gas Transportation Systems, Economic and Risk Analysis, Final Conclusions and Results, prepared for the U.S. Department of the Interior, February 1976.

[2] The Aerospace Corporation, Alaskan Natural Gas Transportation Systems, June 1977 Supplemental, prepared for the U.S. Department of the Interior.

Table II-1
COMPARISON OF NET ECONOMIC BENEFIT ESTIMATES
($ billions, discounted at 10%)

Estimator	SYSTEM Arctic Gas	El Paso	Alcan Express
DOT 6/77 1/	8.0	6.9	8.2
FPC 4/77 2/	7.1	5.8	7.7
DOI 12/75 3/	8.7	8.3	9.0
FPC Staff 12/15/76 4/	6.7	6.3	6.8
Arctic Gas 12/3/76 5/	10.0	3.6	--
El Paso 9/23/76 6/	5.4	6.8	--

1/ Prudhoe Bay flow - 2.4 BCFD, Mackenzie Delta flow - 0.5 BCFD, no western leg.

2/ Prudhoe Bay flow - 2.4 BCFD, Mackenzie Delta flow - 1.0 BCFD.

3/ Prudhoe Bay flow - 2.5 increasing to 3.5 BCFD, Mackenzie Delta flow - 0.5 increasing to 0.9 BCFD, does not include western leg.

4/ Prudhoe Bay flow - 2.5 increasing to 3.5 BCFD, Mackenzie Delta flow - 0.5 increasing to 1.0 BCFD, no western leg, $12/bbl oil price, high non-Alaskan gas supply.

5/ Prudhoe Bay flow - 2.25 BCFD, Mackenzie Delta flow - 2.25 BCFD, includes $2,996 in benefits attributable to maintenance of Canadian imports, costs estimated by Arctic Gas, includes all U.S. taxes as cost.

6/ One-year delay in construction and cost overrun of $900 million for Arctic Gas, Prudhoe Bay flow - 2.4 BCFD.

The end result of these six cost-benefit analyses is to estimate the net national economic benefits of the alternative systems (NNEB). The net economic benefit is the difference between the dollar values of the benefits and the costs in present value or discounted terms.

There are three major shortcomings in all of these estimates of net economic benefits. First, the estimates of capital and operating costs and construction schedule are based on conventional engineering cost-estimating techniques. Previous experience has shown that many standard engineering cost schedule estimates for systems that utilize new and untested technology have been too optimistic, for example, the C5-A airplane and the trans-Alaska oil pipeline. The proposed Alaska natural gas transportation systems face a considerable risk of cost overrun and schedule delay which could lower net economic benefits greatly. Second, the environmental damage caused by these systems has not been valued and included as a cost. Although the applicants have designed their systems to minimize environmental impacts, future changes in the design or routing of these systems may be required in order to mitigate impacts as more information is gained during construction. These additional costs of impact mitigation are obviously not included. Third, all systems are assumed to receive a "go-ahead" from the various governments involved at the same time or, in other words, receive all the necessary permits at the same time from the Canadian and U.S. Governments. If, in fact, one system cannot begin construction until later than another system for any reason, the net economic benefit of that system would be reduced relative to the other systems.

Consequently, the President and the Congress, in choosing between these alternative systems, must consider at least three other factors in addition to net economic benefits. These are the risks of cost overruns and schedule delays, the environmental damage associated with each of the systems, and possible delays in beginning construction. Even if one system may have higher net economic benefits, according to these various cost-benefit studies, that system may not be the preferred system if it will result in greater environmental damage, it has the greater risk of cost overruns and schedule delays, or it will experience a delay in the receipt of the necessary Government permits.

The general result of these estimates of net economic benefits is that the Alcan Express System has net economic benefits slighly greater than Arctic Gas. The net economic benefits of the El Paso System are significantly less than the two overland pipeline systems but are still very large. Looking at the most recent Interior estimates, the net benefits of the Alcan System and Arctic Gas are almost equal. The net economic benefits of El Paso are approximately 19 percent less than for the other two systems. In general, these estimates indicate a preference for Arctic Gas and Alcan over El Paso but the two all-pipeline routes are not overwhelmingly superior to the LNG-tanker system.

Arctic Gas and El Paso have each submitted a cost-benefit analysis that shows their system to be superior to the alternative. In the El Paso cost-benefit analysis, the net economic benefits of the El Paso system are higher than for Arctic Gas because it is assumed that Arctic Gas will experience a cost overrun of $900 million and a one-year delay in construction.

El Paso has argued that they will provide the benefit of employment stimulation in the U.S. to a greater extent than the other systems, though this benefit is actually included in the cost-benefit analysis submitted to the FPC. As discussed at the FPC hearings, such a benefit for any of the systems is doubtful for a number of reasons. Any of these projects may simply divert funds and thus the employment effects from some other private investment with no net gain. The economy may be at a reasonably low level of unemployment and further stimulation would only cause inflation. In any case, there may be little or no unemployment in those types of jobs needed for building pipelines, tankers, and so forth. Employment effects are discussed in more detail in Chapter V of this report.

Arctic Gas estimates that the net economic benefit of its system is almost three times as large as the net benefits of the El Paso system. Arctic Gas achieved this high level of net benefits by making two assumptions that have not been made in any of the other estimates. The first is that the construction of the Arctic Gas system will result in large increases in exports of Canadian gas to the U.S. because the Arctic Gas system will also deliver Mackenzie Delta gas from the Canadian Arctic to Canadian markets and thus, make more gas available in Canada for export. In addition, Arctic Gas argues that this export gas will be sold at a price substantially below the price consumers would be willing to pay and thus, give American consumers considerable economic benefit. Arctic Gas estimates this benefit of greater Canadian exports to the

U.S. at almost $3 billion in its calculation of net economic benefits. The DOI study, the FPC staff, the FPC in its Recommendation to the President, the other applicants, and the Administrative Law Judge at the FPC hearing the case, have concluded that there is a small probability that additional gas exports would be made available at a price below its value to U.S. consumers. Consequently, little or no benefit should be attributed to the Arctic Gas system for maintaining Canadian exports to the U.S.

The second factor that causes the high estimate by Arctic Gas is that Arctic Gas includes as a cost, taxes paid to U.S. Governments, such as corporate income taxes, property taxes, and other local taxes. The widely-accepted practice in cost-benefit analysis is that domestic taxes do not represent a cost to the nation as a whole, though they are a cost to the consumers of Alaskan gas. These taxes will either be returned to other U.S. citizens in the form of transfer payments (such as unemployment compensation, welfare payments), or would result in greater Government services (such as roads, schools, or defense), or result in lower tax rates. However, foreign taxes levied on the project should be included as a cost since these represent a net outflow of funds from U.S. citizens to foreign citizens. This treatment of taxes was used by Interior, the FPC staff, El Paso, and endorsed by the Administrative Law Judge. The FPC in its report to the President agreed that U.S. corporate income taxes should not be included as a cost but that U.S. property taxes should be included. The reason for this is discussed in a later section.

III. A REVIEW OF THE FPC RECOMMENDATIONS

Table III-1 presents a comparison of the cost-benefit analyses in the Recommendation to the President by the FPC and in the recent studies done for the Department of the Interior. This comparison illustrates some of the controversies and uncertainties in undertaking a cost-benefit analysis.

The Interior and the FPC estimates of net economic benefits include a number of benefits and costs. Interior included a benefit for the value of this natural gas to U.S. consumers and also a benefit for the reduction in our dependence upon unreliable foreign sources of energy that would result from the construction of any of these systems. The FPC included a benefit for gas consumption but not for energy independence. The FPC included costs in five categories: the cost of gas production, transportation facilities (including working capital), operation and maintenance, U.S. taxes other than income taxes, and Canadian taxes. The Interior study did not include costs for any U.S. taxes.

The FPC estimates of benefits to consumers from gas consumption assumed a constant value over time for this gas at $2.62 per thousand cubic feet (MCF). Interior assumed a value of $2.53 initially increasing to $2.70 by the end of the century. These estimates of value are based on the cost of the major alternative source of energy which is imported oil. This oil is assumed to have a constant price over time of $12.00 per barrel or roughly equivalent to $2.00 per MCF. A premium is included for gas because of oil refining costs, the non-polluting character of gas, and other factors.

The Department of the Interior study attempted to estimate the benefit to the nation of being less dependent upon unreliable foreign sources of energy which would result from transporting Alaskan gas to market. The FPC argued that this benefit is too elusive to quantify accurately and, in any case, would be approximately the same for all three systems and thus did not include such a benefit.

The costs of gas production in the Interior study are substantially higher than in the FPC study. The Interior study attempted to estimate the incremental costs that would result from producing gas at the Prudhoe Bay field for sale into a pipeline rather than reinjecting the gas if no transportation system were built. Using a different

Table III-1

ESTIMATES OF NET NATIONAL ECONOMIC BENEFITS
(10% Discount Rate, 1975 Prices, Millions $)

	Arctic		El Paso		Alcan	
	FPC	Interior	FPC	Interior	FPC	Interior
Benefits						
Gas Consumption	12,601	13,118	11,606	12,416	13,508	14,142
Energy Independence	--	1,182	--	1,116	--	1,261
Costs						
Gas Production	1,002	1,975	1,002	1,975	1,101	1,975
Transportation Facilities	3,697	3,865	3,687	4,005	3,848	4,720
Operation and Maintenance	304	199	883	682	306	246
U.S. Other Taxes	90	--	238	--	198	--
Canadian Taxes	386	253	--	--	403	289
NNEB	7,122	8,008	5,798	6,870	7,652	8,173

approach, the FPC also attempted to estimate these costs. However, it is likely that they did not include all operating costs for the field, in particular costs for water injection. This results in the lower costs in the FPC report.

The FPC's estimates of the costs for transportation facilities are based with few changes on the estimates made by the applicants. The Department of the Interior employed independent engineering consultants to estimate these costs. In particular, the estimates of capital cost for the Alcan system prepared for the Interior Department are substantially higher than those estimated by the applicant. The FPC in its Recommendation to the President also suggested Alcan's costs were too low.

Interior's estimates of operating and maintenance costs are less than the estimates by the applicants or the FPC. This is probably due to the fact that Interior did not include an overhead charge to cover administrative costs incurred by the parent company operating the system.

The FPC has included U.S. taxes other than corporate income taxes as a cost. These taxes are primarily ad valorem property taxes. One justification for including these taxes as a cost is that they are a proxy for the services that the Federal, State, and local governments will have to provide these three systems. Such services could include roads, police protection, monitoring shipping traffic, and monitoring construction. Though these government services do represent a real cost to the nation and, in theory, should be included, it is very difficult to estimate what these costs will precisely be. In any case, they are likely to be rather small relative to the large capital and operating costs for these systems. The use of property tax payments as a proxy or surrogate measure for the cost of these government services is very imprecise and probably greatly overestimates the cost of these services. For this reason, the Interior study did not include property taxes as a cost.

The estimates of Canadian tax costs in the Interior study were taken from an independent Interior estimate of the cost of service for the three systems. Also, Interior reduced tax costs by an amount equal to 4.6 percent of the total payments made by American gas consumers to the Canadian companies owning the pipelines in Canada. This credit reflects the fact that when these payments are returned to the U.S. to buy goods and services for export approximately 4.6 percent will go to U.S. governments as corporate income taxes.

Finally, in any cost-benefit analysis there is the question of what is the appropriate rate of discount. Interior used 10 percent based on an estimate of the historical real pre-tax cost of capital for U.S. industry. Recent academic studies indicate that the historical pre-tax real rate of return on corporate non-financial assets ranges between 12.4 and 13 percent. The FPC used both 10 percent and 6 percent and argued that the latter represented the "social" rate of discount that should be used by the government. The lower rate also is closer to the real rate of return earned by private investors after corporate income taxes. The Office of Management and Budget has recommended the use of 10 percent. The major issue is whether the rate of discount appropriate for Government, industry, or consumers is the one to use for these systems, or perhaps an average of all three.

Western Leg

An important issue is whether or not the Arctic Gas and Alcan Systems should include pipelines for direct delivery of gas to West Coast markets instead of by displacement. The FPC staff has argued that such a West Coast delivery system is not needed since displacement can deliver the gas at less cost. Arctic Gas, Alcan, and other intervenors have argued for its construction. The FPC in its report to the President recommended that a decision on these facilities be postponed until more information is available. The Alaska Natural Gas Transportation Act may require such facilities.

In any case, it is difficult to see how including or excluding the Western Leg would significantly affect the net economic benefits of either the Arctic Gas or Alcan systems. Including the Western Leg would increase construction costs for both systems and thus reduce net economic benefits. However, Arctic Gas has argued that the construction of the Western Leg would reduce the amount of gas necessary for fuel to power the various components of the delivery system in the lower 48 states. This reduction in fuel usage would increase net economic benefits and roughly offset the higher capital costs.

Capital Cost

Table III-2 shows construction costs estimated by the applicants and by consultants to the Department of the Interior. The FPC, in the Recommendation to the President, used estimates by the applicants for calculating net economic benefits.[3] As stated earlier, the Interior Department employed independent consultants to estimate these costs. For the most part, these estimates do not differ greatly. This indicates that two independent terms of engineering cost estimators have arrived at approximately the same cost for these systems. However, this does not rule out the possibility of large cost overruns or schedule delays as has been the case in the past with other large complicated projects utilizing a great deal of new technology and techniques.

The one major difference between the capital cost estimates by Interior and the applicants is for the Canadian portion of the Alcan Highway System. The FPC, in its Recommendation to the President, said that Alcan's costs in Canada are probably too low by a factor of 10 percent or more. Alcan has argued in a statement to the FPC that these costs represent historical costs incurred by Canadian pipeline companies. In the estimates for the Department of the Interior, the costs for the Canadian portion of the Alcan system are comparable with construction costs estimated for the El Paso system in similar areas in Alaska and for the Arctic Gas system in similar areas in Canada. Alcan's estimates are generally lower. As shown in Table III-2, Interior's estimates for costs in Canada are 70 percent higher than the estimates by Alcan. It is probably not reasonable for Alcan to assume that the historical cost of building smaller-scale pipeline projects in more southern areas of Canada will be a good predictor of future costs for building a system on the huge scale of the Alcan Highway proposal.

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[3] The values in Table III-2 for the estimates by the applicants differ slightly from those in the FPC Recommendation to the President because of minor errors in the FPC report and disagreements about the inclusion of certain cost components.

[4] For a detailed discussion of the differences between Alcan's and Interior's estimates, see U.S. Department of the Interior, Alaskan Natural Gas Transportation System: A Report to the Congress pursuant to PL 93-153, December 1975.

Table III-2

Estimates of Construction Cost
($ Million in 1975 Prices Excluding AFUDC and Working Capital)

System	Applicant	Interior 1/	Ratio Interior/Applicant
El Paso			
Pipeline	1,861	1,963	1.05
LNG Plant	1,434	1,591	1.11
Shipping	1,282	1,234	0.96
Regasification	322	304	0.94
Lower 48 pipelines	621	530	0.85
Total	5,520 2/	5,622	1.02
Arctic Gas			
Alaska	556	555	1.00
Canada Main Line	4,594 3/	4,552	.99
(U.S. share)	(3,423) 4/	(3,869) 5/	(1.13)
Eastern Leg	931	1,011	1.09
Subtotal	6,081	6,118	1.01
(U.S. share)	(4,910)	(5,435)	(1.11)
Western Leg	737 6/	-------	------
Total	6,817 7/	-------	------
(U.S. share)	(5,646)	-------	------
Alcan Express			
Alaska	2,058	1,812	0.88
Canada Main Line	2,081 8/	3,597	1.73
Eastern Leg	931	1,011	1.09
Subtotal	5,069	6,420	1.27
Western Leg	711 9/	-------	------
Total	5,781 10/	-------	------

1/ Prudhoe Bay flow of 2.4 BCFD, Mackenzie Delta 0.5 BCFD.

2/ Prudhoe Bay flow - 2.3614 BCFD.

3/ Canadian Arctic costs less $128 million for Caroline to B.C. border.

4/ .7533 of Canadian Arctic costs less $128 million for Caroline to B.C. border.

5/ .85 of costs in Canada.

6/ Costs for PGT, PGE, ANG plus $128 million for Caroline to B.C. border.

7/ Prudhoe Bay flow of 2.40 BCFD, Mackenzie Delta 1.00 BCFD.

8/ Costs for Foothills-Yukon, Foothills-Saskatchewan, Westcoast-North and Alberta Gas Trunk less $74.26 million for line between Caroline and B.C. border.

9/ Costs for PGT, PGE, and Westcoast-South plus $74.26 million for line between Caroline and B.C. border.

10/ Prudhoe Bay flow - 2.40 BCFD.

Construction Schedule

Both Arctic Gas and El Paso estimate a construction schedule of approximately five and one-half years. Alcan estimates a construction schedule of only three and one-half years. The FPC, in its Recommendation to the President, argued that Alcan was being optimistic and that a more realistic estimate would be nine months longer. Independent estimates for the Interior Department confirm this conclusion. Estimates of net economic benefits and cost of service done for Interior assume a construction schedule for Alcan of approximately four and one-half years. This shorter construction schedule still gives Alcan a major advantage in terms of either net economic benefits or cost of service. Alcan is able to achieve this shorter schedule because of less reliance on winter construction and an all-weather transportation system when compared to Arctic Gas.

Gas Fuel Usage

All three systems will use some of the input gas at Prudhoe Bay to power various components of the transportation system, such as compressor stations, refrigeration units, LNG plant, tankers, and so forth. Table III-3 presents estimates by the FPC in its Recommendation to the President, by the applicants before the FPC, and by consultants to the Department of the Interior of the amount of input gas used as fuel. Again, estimates by Interior and the applicants are approximately the same. The small differences might be explained through simple differences in estimating techniques or because of small differences in flows. The FPC estimated fuel requirements for Arctic Gas by scaling up an estimate by Arctic Gas for a lower flow rate. This FPC estimate is probably too high.

Transportation Cost

Transportation cost (cost of service) alone is an inadequate measure of the relative economic merit of the alternative proposals when compared to cost-benefit analysis. The results of the comparison of transportation cost will differ from the results of a cost-benefit analysis for at least four major reasons. The first is that estimates of transportation cost treat all taxes equally. In other words, both American and Canadian taxes are included as a cost to the final consumer. However, this

Table III-3

Estimates of Gas Fuel Requirements
(Gas Used as Fuel Stated as Percent of Input)

	FPC	Applicant	Interior[1/]
Arctic	6.3[2/]	5.5%[2/]	5.7%
Alcan	6.3[3/]	6.4[3/]	6.3
El Paso	10.9[4/]	10.9[4/]	10.9

1/ Prudhoe Bay flow 2.4 BCFD. Mackenzie Delta flow 0.5 BCFD.

2/ Prudhoe Bay flow 2.4 BCFD. Mackenzie Delta flow 1.0 BCFD.

3/ Prudhoe Bay flow 2.4 BCFD.

4/ Prudhoe Bay flow 2.3614 BCFD.

fails to recognize the fact that American tax revenues will be used to benefit all American citizens. Second, these estimates of transportation cost include gas fuel as a cost at a rate of $1 per million BTU. The cost-benefit methodology values this gas at the price consumers will be willing to pay for this gas or approximately $2.62 per million BTU. Third, the transportation cost does not include any credit for the benefit that this gas provides by making us less dependent on unreliable foreign sources of energy. Fourth, the net economic benefit methodology gives much greater weight to prompt delivery of the gas. A longer construction schedule will reduce the benefits of the gas to consumers (in present value terms) and substantially lower net economic benefits. The cost of service approach only penalizes a longer construction schedule by increasing the total interest charges on the facilities during construction or, in other words, the allowance for funds used during construction (AFUDC).

The FPC, in its Recommendation to the President, makes a valuable innovation in the calculation of transportation cost. In the estimates presented at the FPC hearings by the applicants, capital and operating costs were in constant 1975 prices, but financing costs were in nominal or inflated dollars. This resulted in a transportation cost that was neither in constant dollars nor in inflated nominal dollars. The FPC requested the applicants to reestimate the unit or average transportation cost entirely in 1975 constant dollars. Table III-4 presents a twenty-year simple average as calculated by the applicants according to the FPC methodology for the three systems.

There is a major weakness, however, in the presentation of a simple average transportation cost over a twenty-year period for the three systems. This ignores differences in the time profile of transportation cost. The transportation costs of the three systems changes greatly over time. Two systems would have the same simple twenty-year average even if one system would have a very high cost initially, while the other system would have a high transportation cost late in the life of the system. Because of the time value of money, the latter would be preferred. Another approach to measuring the overall transportation cost is to calculate a leveled average. The leveled average transportation cost is that rate which is constant over time but which has the same present value as the non-constant rates estimated by the applicants. In general, the leveled average rate is higher than the simple twenty-year average because the annual transportation rate declines over time.

Table III-4

Estimates of Transportation Cost - National Average
(Dollars per million BTU in 1975 dollars)[1/]

	Twenty Year Simple Average		Leveled Average	
	Applicant	Interior	Applicant	Interior
Arctic[2/]	$0.72	$0.70	$0.87	$0.85
El Paso	$1.09	$0.92	$1.26	$1.09
Alcan	$0.79	$0.84	$0.95	$1.03

1/ Applicant Flow Rates:

Arctic: Prudhoe Bay 2.4 BCFD
Mackenzie Delta 1.0 BCFD

El Paso: Prudhoe Bay 2.36 BCFD

Alcan: Prudhoe Bay 2.4 BCFD

Interior Flow Rates:

Arctic: Prudhoe Bay 2.4 BCFD
Mackenzie Delta 0.5 BCFD

El Paso: Prudhoe Bay 2.4 BCFD

Alcan: Prudhoe Bay 2.4 BCFD

Average starting from first year of full flow.

2/ Artic Gas has also estimated a cost of service for the two competing systems using the FPC method but using estimates by Arctic Gas of costs and schedule. The leveled average cost of service calculated from the Arctic Gas estimates is:

Arctic Gas $0.97/million BTU
Alcan $1.13/million BTU
El Paso $1.50/million BTU

Note that these estimates are based on 2.25 BCFD flow from Prudhoe rather than 2.4 BCFD used above.

Table III-4 also gives a leveled average based on the applicant estimates (10% discount rate). Consultants to the Department of the Interior have calculated a simple average and a leveled average based on independent estimates of capital costs which are also given in Table III-4.[5]

The general conclusion from the examination of the leveled average rate calculated by Interior is that the transportation cost for the Arctic Gas system is the lowest while that of Alcan is 21 percent higher, and for El Paso 28 percent higher. To illustrate the differences between the net economic benefits approach and the cost of service approach, recall that Alcan had net economic benefits slightly higher than Arctic Gas.

The estimate of transportation cost by Interior for the El Paso system is less than that estimated by El Paso. This is probably due to the fact that Interior uses the same financial assumptions for all components of all systems. This results in a lower return on equity and a higher debt/equity ratio than that assumed by El Paso for the LNG tanker portion of its system. This assumption by Interior would produce a lower estimate of transportation cost for the LNG tankers. In the recent studies for Interior, this assumption was justified on the basis that an unfair comparison of transportation costs would result if different financial structures or different rates of return on investment were assumed for the various systems. Interior's estimate of transportation cost for the Alcan system is higher than that estimated by Alcan. This is the result of the higher construction costs assumed by Interior for facilities within Canada and the one-year longer construction schedule. Another factor might be differences in the financial assumptions used.

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[5] Using Interior's estimate of construction and operating costs and construction schedule, the FPC calculated total annual cost of service in inflated prices for each system. Unit or average constant dollar costs including a charge for fuel were then calculated by Interior's consultants. The FPC used cost of service computer models supplied by Arctic Gas. The Northern Border model was used for segments of all systems in the U.S. The Canadian Arctic model was used for Canadian segments of all systems.

The transportation costs given in Table III-4 are an average over the whole nation based on an assumed distribution of the Alaskan gas. The transportation cost to any particular region may be higher or lower than this national average. The difference between regions is not likely to be substantial for the Alcan and Arctic Gas systems. However, under the El Paso system, Alaska gas is likely to be substantially cheaper for the West Coast than the rest of the country. The simple 20-year averages calculated by the FPC show that transportation cost to the West Coast under the El Paso system would be approximately 30 percent cheapter than to the rest of the nation.

Prudhoe Bay Price

The transportation costs given in Table III-4 do not include a purchase price or wellhead price which would be paid to the petroleum companies owning the Prudhoe Bay field. Interior in the 1975 report to Congress calculated that a price of $.47 per thousand cubic feet (roughly one million BTU) would just cover the incremental costs of producing and processing the gas for sale into a pipeline in addition to the oil. This figure assumed 1975 costs and a 10 percent pretax rate of return on investment. Many would argue that such a low price greatly discourage future exploration efforts on the North Slope. The FPC and the applicants have used an "illustrative" price of $1.00 per MCF. The price may be affected by Federal regulation which is dependent upon the outcome of legislation now before the Congress.

If one assumes a wellhead price of $1.00 per million BTU, the total delivered cost of this gas using the Interior estimates of the leveled average would be $1.85 per million BTU for Arctic, $2.03 for Alcan, and $2.09 for El Paso. Though this would be expensive gas by historical standards, it seems cheap relative to other supplementary sources of gas such as coal gasification or imported LNG and is comparable to the cost of imported oil (approximately $2.25 per million BTU assuming a price of $13.50 per barrel without refinery processing costs). Because of the special characteristics of gas (clean burning, a gas rather than a liquid), most users would be willing to pay a premium for gas over oil.

IV. RISK AND SENSITIVITY ANALYSIS

INTRODUCTION

This section covers three subjects: first, new base case assumptions about the three proposed systems are presented that differ in a number of significant ways from those in the FPC report to the President or in the recent analysis for the Department of the Interior; second, a sensitivity analysis is presented that shows how net national economic benefit changes as certain key assumptions or parameters are altered (i.e., discount rates, value of the gas, construction costs, and construction schedule); third, cost of service and net national economic benefit are presented, assuming various cost overruns and schedule delays, Estimates for these overruns and delays are presented in the task force report on risk of cost overruns and schedule delays. For a more detailed discussion of how these estimates of cost overruns and delays were derived, see the separate interagency task force report on that subject.

TASK FORCE BASE CASE

Development of a base case is useful to conduct a sensitivity analysis. The base adopted for the net economic benefit calculations generally follows the cost-benefit methodology used by the Federal Power Commission, rather than the somewhat different methodology used by the Department of Interior. It was not concluded that the methodology used by the FPC was necessarily superior to that used by Interior; however, to facilitate a comparison with the FPC report, their methodology was adopted. However, this base case does makes certain assumptions differ from those made in the FPC report and they are described below. The unchanged assumptions are a 10 percent discount rate; a constant value of the gas at $2.62 per million BTU; and construction schedules for the three systems. The construction schedule for Alcan is assumed to be nine months longer than that proposed by the applicant.

Arctic Gas Base Case

The major change from the FPC report is to reduce the gas fuel used by the Arctic Gas system from 6.31 percent of the input gas to 5.51 percent. As mentioned earlier, the FPC earlier estimated the gas fuel required for a flow of 2.4 BCFD through the Arctic Gas system. The applicant estimates a fuel requirement of 5.51 percent which is adopted for the base case. Consequently, annual gas delivery by the Arctic system to the United States increases from 942.2 to 950.2 billion BTU.

Other minor changes to the FPC report's assumptions include raising construction costs for Arctic by about $15 million. Approximately $10 million is added because of the need for additional compression horsepower on the Pacific Gas Transmission line at the higher flow of 2.4 BCFD. The costs in the FPC report are based on a flow of 2.25 from Prudhoe Bay. Finally, a small transcription error for other Canadian taxes in 1983 is corrected by increasing the value from $0.5 million to $4.7 million.

El Paso Base Case

Late in the preparation of this report, it came to the attention of the task force that the FPC in the Recommendation to the President included working capital as a cost both in the cost of transportation systems and as a separate cost item in the calculation of net economic benefits for the El Paso system. This overstates the costs of the El Paso system by about $63 million or less than one percent of total capital and operating costs. Time was not available to correct this error in the base case or the following sensitivity analysis. As a result the net economic benefits of the El Paso system in the base case are understated by $34 million or 0.6 percent.

Alcan Base Case

The FPC concluded that the estimate of construction costs by Alcan for the pipelines within Canada was probably too low by about 10 percent. Consultants to the Department of the Interior found that construction costs estimated by Alcan for facilities in Canada were too low by as much as 70 percent. In a recent submittal to the Federal Power Commission, Arctic Gas included estimates of costs for the Alcan system in Canada that were about 20 percent higher than the costs estimated by Alcan itself. Faced with these conflicting estimates, the task force decided on a compromise which raises the costs for Alcan within Canada by approximately 30 percent. This amounts to a 11 percent increase in total costs for Alcan. Canadian taxes are also raised by 30 percent to reflect the higher assumed construction costs.

Base Case Net Economic Benefits

Table IV-1 gives the estimates for net national economic benefits for the base case. The FPC estimates are also shown for purposes of comparison.

The net economic benefits for El Paso are almost unchanged. The net benefits for Alcan are reduced by about 7 percent (at the 10 percent discount rate) because of the higher capital costs in the base case. The net benefits for Arctic Gas are increased by 3 percent because of the greater delivery of gas. The general result, therefore, is little change from the FPC Recommendation to the President. Alcan and Arctic Gas have approximately the same large net benefits and have net benefits approximately 25 percent higher than El Paso.

SENSITIVITY ANALYSIS

Value of Natural Gas

Various assumptions in the base case are altered to determine the sensitivity of net benefits to changes in key parameters. Table IV-2 shows net economic benefits for a number of different assumptions about the future value of natural gas to U.S. customers. This table shows that the higher the value, the greater the net economic benefits.

As noted in the FPC Recommendation to the President, "...if recent projections of world-wide hydrocarbon shortages within a decade materialize, (the) analysis understates the benefits of all three systems." In the light of recent reports suggesting a more rapid draw-down on world oil reserves than previously anticipated, it seems reasonable to project some escalation in world oil prices and thus in the value of natural gas instead of the constant value assumed by the FPC. Assuming a 2 percent annual increase in the value of gas (above the general inflation rate), the net economic benefits of these systems (at a 10 percent discount rate) increase by 66 percent. For completeness, net economic benefits are also presented assuming a declining value of natural gas. This could come about due to a fall in the world price of oil, major new sources of

Table IV-1

Working Group Base Case Net National Economic Benefit
(Millions of 1975 dollars)[2,3]

	Arctic			El Paso[4]			Alcan		
	13%	10%	6%	13%	10%	6%	13%	10%	6%
Value of gas less:	8,755	12,708	22,246	7,996	11,606	20,317	9,525	13,508	22,890
Field Gathering & Conditioning	858	961	1,124	858	961	1,124	969	1,057	1,192
Field O&M	28	41	71	28	41	71	31	44	75
Transportation Facilities	3,196	3,612	4,285	3,243	3,650	4,301	3,784	4,242	4,974
Working Capital	13	15	19	28	34	43	23	28	36
System O&M	211	304	527	688	883	1,545	215	306	520
U.S. Other Taxes	67	90	139	175	238	373	151	198	292
Canadian Income Taxes	234	355	648	0	0	0	296	399	624
Canadian Other Taxes	23	32	54	0	0	0	86	121	203
NNEB	4,125	7,298	15,379	3,056	5,800	12,859	3,968	7,113	14,974
FPC NNEB[1]	--	7,112	15,149	--	5,798	12,856	--	7,652	15,655

1/ Federal Power Commission Recommendation to the President - Alaska Natural Gas Transportation Systems, Chapter IV, p. 11.

2/ Assumes no growth in unit value of natural gas.

3/ Assumes approximately 2.4 Bcf/day delivery rate for each system.

4/ Incorrectly includes the cost of working capital in the cost of transportation facilities as well as a separate cost item.

Table IV-2

Sensitivity of the Net National Economic Benefit to Variations in (1) Unit Value of Natural Gas and (2) Discount Rate
(Millions of 1975 dollars)

		Proposal					
		Arctic		El Paso		Alcan	
Value in Year 2000 ($ per million BTU)	Annual Change in Unit Value (Percent)	13%	10%	13%	10%	13%	10%
$1.58	-2%	1896	3887	1020	2685	1668	3662
2.04	-1	2922	5448	1957	4110	2731	5247
2.62	0 1/	4125	7298	3056	5800	3968	7113
3.36	+1	5538	9498	4347	7810	5412	9315
4.30	+2	7204	12,122	5868	10,206	7100	11,921
5.49	+3	9171	15,259	7665	13,071	9080	15,014

1/ This reflects the "Base Case" as shown in Table IV-1 under assumption of constant unit value of natural gas.

natural gas, or the availability of some other inexpensive source of energy.

Project Postponement

An important issue is the cost of the delay in beginning construction that might result from failure to receive the necessary Government permits in the U.S. or Canada, inability to obtain financing, or for some other reason. From the perspective of net national economic benefits, this depends primarily on the discount rate assumed and the future value of natural gas.

Tables IV-3, IV-4, and IV-5 present values of net national economic benefits for delays in the beginning of construction and for a range of discount rates and future values of gas. Note that construction cost and schedule is unchanged and only the "go-ahead" to begin construction is delayed. At a high discount rate and constant or decreasing value for the gas, the reduction in net economic benefits from postponement of construction is large. On the other hand, at a low discount rate and rapid increase in the value of the gas, postponement of construction could actually increase the net benefits of the project.

For example, Table IV-5 shows that at a 13 percent discount rate and no growth in gas value, net benefits are reduced by 13 percent for each year of delay. Table IV-3 shows that at a 6 percent discount rate and 2 percent growth rate in gas value, net benefits are reduced by only 3 percent for each year of postponement.

This analysis of postponement of construction, however, does not consider any effects this might have on the operation of the Prudhoe Bay field. The separate report on gas supply states that postponement of the delivery of gas into a pipeline longer than the 5 years now planned would increase capital and operating costs for the field. Also, 7 percent of the gas produced with the oil would be required to power reinjection compressors if the gas must be reinjected into the field.

Delay in Startup

A second type of delay implies a late commencement in the flow of gas or "startup" of the project even though the system has already been built. Although the situation is

Table IV-3

Sensitivity of the Net National Economic Benefit to Project Postponement (Millions of 1975 dollars)

	(Discount Rate: 6%)					
Annual Change in Unit Value (percent):	Arctic		El Paso		Alcan	
	0%	2%	0%	2%	0%	2%
Number of Years Delay						
0 1/	15379	24829	12859	21490	14974	24127
1	14546	24060	12148	20837	14177	23416
2	13757	23307	11476	20198	13420	22718
3	13008	22572	10840	19574	12701	22032
4	12299	21855	10238	18965	12018	21360
5	11628	21155	9670	18371	11371	20702

1/ This zero delay case is the same as reported for the respective systems as noted in Table IV-1.

Table IV-4

Sensitivity of the Net National Economic Benefit to Project Postponement (Millions of 1975 dollars)

	(Discount Rate: 10%)					
	Arctic		El Paso		Alcan	
Annual Change in Unit Value (percent):	0%	2%	0%	2%	0%	2%
Number of Years Delay						
0 1/	7298	12122	5800	10206	7113	11921
1	6655	11360	5283	9580	6498	11202
2	6068	10640	4812	8988	5934	10519
3	5532	9963	4382	8429	5418	9872
4	5043	9324	3991	7901	4945	9261
5	4596	8724	3634	7404	4513	8682

1/ This zero delay case is the same as reported for the respective systems as noted in Table IV-1.

Table IV-5

Sensitivity of the Net National Economic Benefit to Project Postponement (Millions of 1975 dollars)

Annual Change in Unit Value (percent):	Arctic 0%	Arctic 2%	El Paso 0%	El Paso 2%	Alcan 0%	Alcan 2%
	(Discount Rate: 13%)					
Number of Years Delay						
0 1/	4125	7204	3056	5868	3968	7100
1	3664	6598	2712	5391	3534	6530
2	3254	6040	2406	4950	3147	6000
3	2889	5525	2134	4542	2801	5508
4	2565	5052	1893	4164	2492	5053
5	2277	4616	1679	3816	2217	4631

1/ This zero delay case is the same as reported for the respective systems as noted in Table IV-1.

not realistic (since a delay during construction usually results in an increase in costs) it isolates the effect of delay during construction from the effect of cost overruns or changes in other parameters. As Table IV-6 shows, delay in gas delivery greatly reduces net economic benefits because the costs have already been incurred and the benefits of gas consumption are delayed. At a 13 percent discount rate, the net benefits are reduced by approximately 25 percent for the first year of delay and over 50 percent for a two-year delay. This fact helps to explain why a firm might decide to spend a great deal of money to keep a construction project on schedule such as occurred with the trans-Alaska oil pipeline.

Reduction in Gas Production

The report dealing with gas supply discusses the future delivery rates from the Prudhoe Bay field. Until some production history is available, there will be uncertainty about the future rate of gas production allowed from the field.

This leads to the issue of the sensitivity of the estimates of net economic benefits to changes in the gas throughput of the systems. Table IV-7 gives the constant daily production of gas over the life of the system that would reduce the net economic benefits of each system to zero assuming various discount rates and future values of gas.[6] For the base case assumption of a 10 percent discount rate and no growth in gas value, net economic benefits are reduced to zero with a flow of gas reduced to about 1.0 BCFD. According to the separate report on gas supply, a conservative estimate of production from the field by both the State of Alaska and the petroleum companies owning the field is 2.0 BCFD. The base case assumption used here is 2.4 BCFD.

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[6] As field production is reduced, the proportion of the gas needed as fuel also declines and some compressor horsepower will not be needed which reduces cost. To a slight degree, these two factors offset the reduction in NNEB from reduced gas production. These factors are not considered in Table IV-7.

Table IV-6

Sensitivity of the Net National Economic Benefit to Natural Gas Delivery Delay[1,2]
(Millions of 1975 dollars)

Number of Years delay	Arctic		El Paso		Alcan	
	13%	10%	13%	10%	13%	10%
0[3]	4,125	7,298	3,056	5,800	3,968	7,113
1	3,117	6,143	2,136	4,745	2,873	5,885
2	2,226	5,093	1,322	3,786	1,903	4,769
3	1,437	4,138	601	2,914	1,045	3,754
4	739	3,270	-35	2,121	285	2,831
5	121	2,481	-599	1,401	-386	1,992

1/ This assumption refers to annual incremental delays in natural gas delivery, but not to any postponement or reductions in project costs.

2/ Assumes no growth in the unit value for natural gas.

3/ This zero delay case is the same as reported for the respective systems as noted in Table IV-1.

Table IV-7

Magnitude of Reduction in Natural Gas Thru-put that Produces Zero Net National Economic Benefit

Assumption		Proposal					
		Arctic		El Paso		Alcan	
Discount Rate (percent)	Annual Change in Unit Value (percent)	BCF/D [1/]	%Δ [2/]	BCF/D	%Δ [2/]	BCF/D	%Δ [2/]
13.0	0.0	1.27	-47.1	1.48	-38.2	1.40	-41.7
10.0	0.0	1.02	-57.4	1.20	-50.0	1.14	-52.7
10.0	2.0	0.74	-69.1	0.87	-63.7	0.84	-65.1
06.0	0.0	0.74	-69.1	0.88	-63.3	0.83	-65.4

1/ Billion cubic feet per day; the base case in each of the proposals assumes 2.4 BCF/D.

2/ Percent change from base case flow.

Cost Overruns

In addition to the risk of delays during construction or in project startup, there is the risk of cost overrun. Table IV-8 provides estimates of net economic benefits for increases in costs above the base case estimates. These estimates assume that the construction schedule is unchanged and only costs increase. In fact, both could happen.

Table IV-8 shows that El Paso could experience a 100 percent cost increase before net economic benefits are reduced to zero (at a 10 percent discount rate and no growth in gas value). The other systems could experience even larger cost overruns before net benefits are reduced to zero.

RISK ANALYSIS

Expected Value Case

This section provides estimates of net economic benefits and cost of service based on "expected values" for cost overrun and schedule delay. These "expected values" were determined by the interagency task force concerned with the risks of costs overruns and schedule delays. For a description of how these estimates were derived and their implications, see the task force report Cost Overrun Construction and Delay.

Net Economic Benefits

Using the same expected value estimates for cost and schedule presented in the separate report on risks, the net economic benefit of the three systems is also calculated and is shown in Table IV-9. Tax estimates are taken from the cost of service calculations described above and are deflated to 1975 dollars. Field gathering and conditioning costs and their schedule of expenditure are unchanged. This is justifiable because the delay in pipeline construction would not become known until the construction of gas facilities at the field are underway. Field O&M costs are postponed in accordance with the delay in project startup.

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[7] In probabilistic terms, the "expected value" is the mean of the distribution of possible values.

Table IV-8

Percent Increase in Gross Project Cost that Produces Zero Net National Economic Benefit[1/]

Assumptions		Project		
Discount Rate	Annual Change in Unit Value (percent)	Arctic	El Paso	Alcan
13	0	89	62	71
10	0	135	99	111
10	2	224	176	186
6	0	224	172	189

1/ All costs shown in Table IV-1 are assumed to increase.

Table IV-9

The Effect on NNEB of Expected Project Cost Overrun and Schedule Delay[3/]
(Millions of 1975 dollars)

	Arctic			El Paso			Alcan		
	13%	10%	6%	13%	10%	6%	13%	10%	6%
Value of gas[2]	7297	11056	20557	7076	10551	19167	7856	11649	21013
less:									
Field gathering & conditioning	858	961	1124	858	961	1124	969	1057	1192
Field O&M	22	34	64	25	37	67	24	37	67
Transportation Facilities	4762	5503	6733	3780	4361	5318	4113	4701	5666
Working Capital	13	15	19	28	34	43	23	28	36
System O&M	166	251	469	538	802	1458	169	253	463
U.S. Other Taxes	110	154	250	325	449	716	172	235	368
Canadian Income Taxes	503	775	1440	0	0	0	228	352	657
Canadian Other Taxes	13	53	92	0	0	0	107	162	299
NNEB	827	3311	10366	1522	3908	10441	2051	4825	12265
(Base Case)[1/]	4125	7298	15379	3056	5800	12859	3968	7113	14974

1/ Working group base case as shown in Table IV-1.

2/ Assumes no growth in unit value of natural gas.

3/ Derived from computations detailed in the report of the Cost Overrun task force.

The net economic benefits of all three systems is still large when expected values of cost overruns and schedule delays are included at the 10 percent discount rate, they range from approximately $3 to $5 billion.

The major change from the base case is that the rank ordering of the three systems in terms of net economic benefits has been altered. Alcan still has the highest net benefits, but Arctic Gas now has the lowest benefits with El Paso in between.

Perhaps the single most important measure of the economic merit of the alternative systems is net national economic benefits based on expected values of cost overrun and schedule delays. However, these estimates do not consider at least one other important factor. This is the cost of environmental damage.

Cost of Service

Using cost of service models supplied by the Federal Power Commission,[8] the working group estimated unit cost of service and total delivered cost for each system based on the expected values for construction cost and schedule. These results are given in Table IV-10.

The delivered cost includes a $1.00 per million BTU price for the gas at Prudhoe Bay. The task force has not concluded that this is a reasonable price, but is following the precedent set by the FPC and applicants by using this as an "illustrative" price. The cost of service based on the applicant costs was taken from submittals to the FPC by the applicants.

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[8] The Canadian Arctic model supplied to the FPC by Arctic Gas was used for all segments of systems within Canada. The Northern Border model supplied by Arctic Gas was used for all segments of systems in the U.S. except for the LNG tankers. For the tankers, the FPC used an in-house model for financial analyses of tankers. To the extent possible, the financial and other assumptions made by the applicants were used in calculating cost of service. The construction costs and schedule estimated by the applicants was also used in these models, and results very close to the estimates by the applicants were obtained.

Table IV-10

Estimates of Delivered Cost - National Average (per million BTU in 1975 dollars including an illustrative price of $1.00 at Prudhoe Bay and for gas fuel)

	Twenty Year Simple Average1/	Leveled Average1/
Arctic Gas2/		
Applicant Costs5/	1.72	1.87
Expected Value Case	2.09	2.32
Worst Case	3.11	3.61
Alcan3/		
Applicant Costs5/	1.79	1.95
Expected Value Case	2.09	2.33
Worst Case	2.96	3.39
El Paso4/		
Applicant Costs5/	2.09	2.26
Expected Value Case	2.26	2.50
Worst Case	2.78	3.14

1/ Average calculated over first 20 years of flow including years of partial flow except for "applicant cost" case. Here first 20 years of full flow was used.

2/ Flows: Prudhoe Bay - 2.4 BCFD, Mackenzie Delta - 1.00 BCFD.

3/ Flow: Prudhoe Bay - 2.4 BCFD.

4/ Flow: Prudhoe Bay 2.36 BCFD.

5/ Taken from submittals to the Federal Power Commission.

The general conclusion is that the delivered cost for all three systems are substantially increased when the expected values of cost overruns and schedule delays are included. However, all three will still have a delivered cost ranging between \$2.32 and \$2.50 per million BTU. These prices seem competitive with other sources of energy. For example, they are roughly equivalent on a BTU basis to oil at \$13.50 per barrel oil (approximately \$2.25 per million BTU).

Because El Paso is expected to have less cost overruns and delays than the other two systems, the difference in the cost of service between these systems has been narrowed. Based on the applicant's costs, El Paso has a delivered price roughly 20 percent higher than the other systems. In the expected value case, the gas has narrowed to 10 percent or less. The delivered cost for Arctic and Alcan are almost identical.

Worst Case

The same task force estimated an upper bound or "worst case" of overrun and delay. The chance of the system exceeding this estimate of cost and schedule is estimated at less than 5 percent in probabilistic terms. Such an upper bound or "worst case" is useful in determining the exposure of the U.S. Government if a Federal guarantee for financing were to be made available. However, this estimate should not be used to determine which of the systems promises the most or least benefit for the U.S.

Net Economic Benefits

Table IV-11 shows the net benefits for the three systems in the unlikely event that the worst case of cost overruns and delays occur. Net benefits for Alcan and El Paso are still positive (assuming a 10% discount rate and no growth in gas value). Net benefits for Arctic Gas become negative primarily because of large cost increases and delays in Canada. Also, corporate income taxes and property taxes in Canada increase because of the larger rate base and thus larger return on the rate base.

Cost of Service

Table IV-10 also provides estimates of delivered cost for "worst" or upper bound case. In the unlikely event that

Table IV-11

The Effect on NNEB of Worst Case Project Cost Overrun and Schedule Delay[3]
(Millions of 1975 dollars)

	Arctic			El Paso			Alcan		
	13%	10%	6%	13%	10%	6%	13%	10%	6%
Value of gas[2]	5057	8307	17260	5582	8773	17134	5769	9133	17998
less:									
Field Gathering & conditioning	858	961	1124	858	961	1124	969	1057	1192
Field O&M	15	25	53	19	31	60	19	30	59
Transportation Facilities	6340	7536	9610	3996	4790	6168	5035	5971	7584
Working Capital	13	15	19	28	34	43	23	28	36
System O&M	115	189	394	421	663	1297	132	209	412
U.S. Other Taxes	106	160	289	330	481	825	164	240	414
Canadian Income Taxes	963	1543	3026	0	0	0	461	731	1414
Canadian Other Taxes	40	63	120	0	0	0	109	168	315
NNEB	-3391	-2185	2625	-69	1814	7616	-1142	700	6572
Base Case[1]	4125	7298	15379	3057	5800	12859	3968	7113	14974

1/ Working group base case as shown in Table IV-1.

2/ Assumes no growth in unit value of natural gas.

3/ Derived from computations detailed in the report of the Cost Overrun task force.

this case should prove to be the actual result, Arctic Gas would have the highest delivered cost and El Paso the lowest with Alcan in between. Even with these upper bound estimates of cost and schedule, the delivered cost of this gas is not extremely high, ranging between \$3.14 and \$3.61 per million BTU. Many estimates of the cost of synthetic gas from coal or imported LNG equal or exceed these values.

V. SHORT-TERM EMPLOYMENT IMPACTS

This chapter computes the direct and induced employment effects which can be expected from construction of the Alcan, Arctic, and El Paso proposals for the Alaskan Natural Gas Pipeline. These estimates are valid under the assumption that the economy is at less than full employment. These results do not take into account any changes in employment due to changes in gas flows which may result from the project completion. This analysis also does not take account of differences in levels of employment necessary to transport the gas once construction is completed. The post-construction impacts are considered in Section VI.

The estimates are illustrative of the kind of gross employment impacts that may be generated when the economy is at less than full employment. Because there is no way to predict what uses the resources used to construct the Alaska natural gas transportation systems would otherwise have, it is impossible to say with certainty how much net employment would be created.

Methodology

The methodology for estimating the number of jobs generated by the pipeline is divided into two parts. The first part converts pipeline expenditures into the total expenditure change in the U.S. The second part converts the total expenditure change into a change in jobs. The size of the employment impacts will vary depending on the choice of impact assumptions.

The first part of the methodology uses the real short term multiplier from the DRI model to estimate the total change in GNP as a result of U.S. pipe-line expenditures. The value used is 1.9. For reasons developed in the discussion of the second part of the methodology, these changes are split into direct and induced components. For Canadian expenditures the process is somewhat complex. In order to determine the expenditures generated in the U.S. by Canadian pipeline expenditures, the DRI Canadian model was exercised for both a 100 million dollar change in producers durable equipment and 100 million dollar change in construction. The changes in GNP and imports which resulted are given below:

	GNP (Canada)	Imports (Canada)
Producers Durable Equipment	56	84
Construction	117	22

Using the DRI estimate that roughly two-thirds of Canadian imports come from the U.S., the import coefficient per dollar spent in Canada for producers' durable equipment and construction are .56 and .15, respectively. Assuming that pipeline expenditures are half for construction and half for producers' durable equipment yields an import coefficient of .36 for U.S. goods. Data supplied by El Paso indicates that material purchased are 49% of total expenditures.[9] The import coefficient is used to compute the column headed "Canadian Induced" in Tables V-2 through V-4. This column also includes the change in GNP due to the increase in U.S. exports. In Table V-1, the expenditures by year and country are given. The table is based on data provided by the FPC. Materials purchased will be higher for Alcan and Arctic since the pipeline construction process is less labor intensive than the LNG plant and ship construction.

The methodology used to go from expenditures to employment is based upon Okun's law. Specifically, we assume that a 1% increase in GNP generates a .04% decrease in unemployment. Since the concern is not with unemployment but employment, the change in unemployment must be converted into a change in jobs. Since every new job typically increases the labor force by .4 person, thus decreasing unemployment by .6 job, employment changes will be 1 and 2/3 as large as unemployment changes. Therefore, a .1% change in GNP will change employment by .067%. The assumed levels of GNP and the labor force used to generate the percent changes are derived from the April 1977 DRI long range forecast. The values used are presented in Table 21. We have assumed that it takes twice as much expenditure to generate a job on the pipeline as it does for the economy in general. Therefore, for direct U.S. pipeline expenditures, the predicted employment change is divided by 2.

Results

Examination of Tables V-2 through V-5 which present the results for the three proposals indicates tht El Paso has the largest impact, followed by Alcan and Arctic. The differences, while large in an aboslute sense, translate to a .008% difference in the unemployment rate for El Paso over Alcan and a .037% difference for El Paso over Arctic in 1981, the year of the largest difference in employment effects. If the difference in jobs in 1981 were to be made up by additional government deficit, a deficit of 190 million dollars would be required to generate the difference

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[9] Material purchases will be higher for Alcan and Arctic since the pipeline construction process is less labor-intensive than the LNG plant and ship construction.

in jobs between Alcan and El Paso and a deficit of 830 million dollars would be required to generate the difference in jobs between Arctic and El Paso. This computation used a real multiplier for the government deficit of 2.2. The source is again the DRI model.

Comparison with the El Paso Estimates

El Paso has also prepared an analysis of the employment impacts of the pipeline. Examination of their numbers reveals considerably higher employment impacts and much larger differences among the applicants. There are several reasons for these differences.

First, El Paso uses a cost basis of $7.9 billion dollars, appropriate for a 3.2 BCF/D project. However, for the competing projects they use capital costs appropriate to a 2.4 BCF/D projects, thus exaggerating the difference in employment impacts.

Second, in determining the size of the induced employment effects, they use a multiplier of 2.5 as compared the value of 1.9 used in this paper. The result of using the higher capital cost and the larger multiplier is to increse the sum of direct and induced expenditures by over 8 billion dollars, or roughly two thirds of the expenditures used in this analysis. Thus, using the El Paso basis would imply an employment impact of roughly 450,000 jobs over the life of the El Paso project, or about 170,000 jobs in 1981, the year of the largest impact of the El Paso project.

Third, El Paso generates employment impacts by looking at average level of employment per billion dollars of GNP while the analysis in this Chapter uses the marginal change in employment to be expected from an increase in GNP. This Chapter's methodology generates much lower changes in employment. It is appropriate for the problem at hand because the problem is to determine the change in employment given a change in demand.

Fourth, El Paso, in examining the employment impacts of the other two systems, considers the effect on employment of payments to Canada for transmission of gas. Since this Chapter is concerned with the construction phase of the project only, no estimate of these effects is made. This has the effect of reducing the estimated differences in employment presented in this Chapter from those given by El Paso.

Table V-1

Direct Expenditures
(in millions of 1975 Dollars)

	Arctic		Alcan		El Paso
	U.S.	Canadian	U.S.	Canadian	
77-78	0.0	0.0	0.0	68.6	35.6
79	45.5	766.0	206.8	279.1	139.9
80	83.0	1123.7	968.3	727.6	1629.2
81	580.3	1462.8	1337.3	1156.2	2081.5
82	850.9	1159.7	931.7	638.0	1361.5
83	336.4	290.7	3.2	0.4	335.3
84-93	130.6	0.0	92.6	10.4	0.0
	2026.7	4802.9	3539.9	2880.3	5583.0

Table V-2

ARCTIC
Total Expenditure in the U.S. As a Result of Pipeline Expenditure

	U.S. Direct (1)	U.S. Induced (2)	Canadian Induced (3)	Total (2) + (3) (4)
77-78	0.0	0.0	0.0	0.0
79	45.5	40.9	523.9	564.9
80	83.0	74.7	768.6	843.3
81	580.3	522.3	1000.6	1522.8
82	850.9	765.8	793.2	1559.0
83	336.4	302.8	198.8	501.6
84-93	130.6	117.5	0.0	117.5

Jobs Generated by Direct and Induced Expenditures

	Direct	Induced	Total
77-78	0	0	0
79	850	20500	21350
80	1450	29800	31250
81	10050	52800	62850
82	14400	52800	67200
83	5550	16600	22150
84-93	2150	3800	5950
	34450	176300	210750

Table V-3

ALCAN
Total Expenditure in the U.S. As a Result of Pipeline Expenditures

	U.S. Direct (1)	U.S. Induced (2)	Canadian Induced (3)	Total (2) + (3) (4)
77-78	0.0	0.0	46.9	46.9
79	206.8	186.1	190.9	377.0
80	968.3	871.5	497.7	1369.1
81	1337.3	1203.6	790.8	1994.4
82	931.7	838.5	436.4	1274.9
83	3.2	2.9	0.3	3.2
84-93	92.6	83.3	7.1	90.5

Jobs Generated by Direct and Induced Expenditures

	Direct	Induced	Total
77-78	0	1700	1700
79	3750	13700	17450
80	17100	48400	65500
81	23150	69100	92250
82	15800	43200	59000
83	50	100	150
84-93	1500	2900	4400
	61350	179100	240450

Table V-4

EL PASO
Total Expenditure in the U.S. As a Result of Pipeline Expenditure

	U.S. Direct	Induced
77-78	35.6	32.0
79	139.9	125.9
80	1629.2	1466.3
81	2081.5	1873.4
82	1361.5	1225.4
83	335.3	301.8
84-93	0.0	0.0

Jobs Generated by Direct and Induced Expenditures

	Direct	Induced	Total
77-78	650	1200	1850
79	2550	4600	7150
80	28800	51800	80600
81	36050	64900	100950
82	23050	41500	64550
83	5550	10000	15550
84-93	0	0	0
	96650	174000	270650

Table V-5

	Real GNP (1975 Dollars In Billions) From DRI Trendlong0377 Forecast	Civilian Labor Force in Millions (Trendlong0377 Forecast)
1976	1609.2	94.8
1977	1685.8	96.9
1978	1773.1	98.9
1979	1851.9	100.8
1980	1934.8	102.6
1981	2006.2	104.3
1982	2083.0	105.9
1983	2158.4	107.3
1984	2224.5	108.7

VI. LONG TERM MACROECONOMIC IMPACTS

Introduction

Energy sector simulations of three Alaska natural gas transportation systems (Arctic, Alcan, and El Paso) were generated with the Project Independence Evaluation System (PIES). The three transportation system and the base case, which posits no transportation system, were simulated assuming alternative crude oil and natural gas pricing regulations. The alternative regulatory programs include rolled-in natural gas pricing, incremental natural gas pricing, and crude oil and natural gas price deregulation.

This chapter examines the long term, or post-construction, macroeconomic implications of the alternative transportation system. The analysis implicitly assumes that the transportation system is completed and operational by the end of 1980.[10] Macroeconomic simulations with the Data Resources, Inc. (DRI) model of the U.S. economy, based on the PIES simulation results, form the basis for the analysis.

Only the Alcan pipeline system is considered here. Since the PIES simulations provide virtually identical energy sector results for the alternative systems with a given regulatory program, the results of macroeconomic simulations of the other two systems would be similar to those obtained for the Alcan system. The regulatory program assumed has little effect on the energy sector impacts of a particular transportation system relative to the corresponding base case. Thus, macroeconomic impacts of a given transportation system would also be similar with different regulatory programs. Only price decontrol and rolled-in pricing are considered, since the three pipelines have their smallest energy sector impacts with the former regulatory program and their largest energy sector impacts with the latter.

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[10] The 1980 starting date is implied by the methodology used here. PIES estimated impacts for 1980, 1985 and 1990. It assumed that a gas pipeline will be operational in 1985, but not in 1980. Interpolation between 1980 and 1985 implies an operational starting date in late 1980, building up to full capacity in 1985. This assumption does not affect the macroeconomic results.

Methodology

Four scenarios are simulated with the DRI model: the Alcan pipeline with crude oil and natural gas price deregulations, the Alcan pipeline with rolled-in natural gas pricing, and the base case with each of these regulatory programs. The same procedure is used to simulate all four scenarios. First, PIES results are used to modify data in the long term macrosimulation CEASPIRIT, which reflects the long term economic targets of the Council of Economic Advisors. Then the DRI model is exercised generating a macroeconomic simulation of each scenario.

Since the PIES model does not forecast variables which are conceptually consistent with variables in the DRI model, equations are used to translate the data from the former to the latter. Five energy related variables in the DRI model serve as entry points for the PIES data: WPI05, CNGAS72, PCNGAS, MEND1067, and JMEND10. The first entry point, WPI05, is a wholesale price index for fuels and related products and power. Its value is determined from eight energy prices which are generated by PIES. The next two entry points, CNGAS72 and PCNGAS, are the real value of personal consumption expenditures for gasoline and its implicit deflator, respectively. Their values are determined from PIES data for the demand for gasoline and its price. The last two entry points, MEND1067 and JMEND10, denote the real value of imported fuels and lubricants and the corresponding average unit value index. Values for these variables are generated from PIES data for the volumes of imported petroleum and petroleum import prices.

In addition to translating the variables from PIES into concepts consistent with those in the DRI model, another problem must be overcome before the new entry point values can be substituted into CEASPIRIT. PIES results are only available for discrete points in time allowing us to calculate entry point values only for those particular periods, i.e., 1980, 1985, and 1990. The entry point values for other time periods are generated by interpolation using the last historical observations in CEASPIRIT and values calculated from the PIES results.

Macroeconomic Results

As shown in Table VI-1, the Alcan pipeline has little, if any, long term impact on the aggregate economy. This is true regardless of which regulatory program is adopted.

Table VI-1
Macroeconomic Impacts of the Alcan Pipeline with Rolled-In Natural Gas Pricing or Crude Oil and Natural Gas Decontrol Relative to the Corresponding Base Cases

Year	Rolled-In Natural Gas Pricing				Crude Oil and Natural Gas Decontrol			
	Real GNP[1]	CPI[2]	WPI05[3]	RU[4]	Real GNP[1]	CPI[2]	WPI05[3]	RU[4]
1980	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981	0.2	0.0	-0.1	0.0	0.1	0.0	0.0	0.0
1982	0.4	0.0	-0.2	0.0	0.2	0.0	-0.1	0.0
1983	0.5	0.0	-0.3	0.0	0.2	0.0	-0.1	0.0
1984	0.6	0.0	-0.3	0.0	0.3	0.0	-0.2	0.0
1985	0.7	0.0	-0.4	0.0	0.3	0.0	-0.2	0.0
1986	0.8	0.0	-0.5	0.0	0.3	0.0	-0.3	0.0
1987	0.7	0.0	-0.5	0.0	0.3	0.0	-0.3	0.0
1988	0.7	0.0	-0.6	0.0	0.3	0.0	-0.4	0.0
1989	0.7	0.0	-0.6	0.0	0.3	0.0	-0.5	0.0
1990	0.7	0.0	-0.7	0.0	0.4	0.0	-0.6	0.0

[1] Real Gross National Product, differences in billions of 1972 dollars.
[2] Consumer Price Index - Total, percent differences.
[3] Wholesale Price Index - Fuels and Related Products and Power, percent differences.
[4] Unemployment Rate, percentage point differences.

Energy prices provide the most important link between the energy sector and the DRI model. Since the pipeline has little impact on energy prices, and hence on WPI05, it is not surprising that it has such small effects on the simulation results. The largest impacts on real GNP occur during the 1985 to 1990 period. Even then, real aggregate demand in 1972 dollars is less than $1.0 billion higher than the corresponding base cases. Similarly, there are no measurable effects on either the rate of inflation or the rate of unemployment.

The above results only reflect macroeconomic responses to the energy sector impacts of the Alaskan natural gas pipeline. Investment expenditures during the construction phase would have a small, favorable impact on the economy that is not captured in these simulations.

The question of employment impacts after 1985 can not be adequately addressed without knowing the impact of the higher cost-of-service associated with the El Paso project. Although the El Paso project would employ more persons after completion than would either of the other systems, the higher cost-of-service would exert a downward pressure on the economy and the net effect has not been calculated.

VII. SUMMARY

This task force report has presented the national economic impacts of the three alternative Alaska natural gas transportation systems: Alcan, Arctic Gas, and El Paso. Three types of measurements were made in this paper to estimate the value of each system to the United States: (1) Net national economic benefit which is the present value of the difference between future benefits and costs; (2) Cost of service which is the cost of transporting the natural gas from Prudhoe Bay to the Continental United States; and (3) Long and short-term macroeconomic impacts on such variables as employment, consumer prices, wholesale prices, and gross national product. The following are the major findings of this report:

- Even including estimates of expected cost overruns shown in the separate report on this subject, the net national economic benefits of the three systems are large and the delivered cost of the gas is competitive with other sources of energy.

- Based on engineering estimates of cost and schedule without any allowance for cost overruns and delays, the net economic benefits of Alcan and Arctic are about the same and significantly higher than for El Paso. This is true whether the cost estimates by the applicants, the independent estimates prepared for the Department of Interior, or the base case estimates presented in this report are assumed.

- Based on engineering estimates of cost and schedule either by the applicants or by independent consultants to the Department of the Interior, Arctic Gas would have the lowest delivered cost, El Paso the highest, and Alcan in between. Based on the estimates for Interior, the difference from highest to lowest would not be more than about 13 percent.

- Perhaps the single most important measure of the economic merit of the alternative systems is net national economic benefits based on expected values for cost overruns and schedule delays.

- Including the estimates of expected cost overruns and schedule delays, the net national economic benefits of the Alcan system are 23 percent higher than for El Paso and 46 percent higher than for Arctic Gas.

- Including the estimates of expected cost overruns and schedules delays, the delivered cost of the gas under the Arctic and Alcan systems is about the same and about 7 percent less than for El Paso.

- Applying common cost estimating methodology to all three systems shows that the estimates of cost by Alcan for facilities in Canada are lower than the costs of the facilities on the El Paso or Arctic Gas System in similar areas by as much as 70 percent.

- Based on the estimates by the working group on risks, the upper bound or worst case values for cost and schedule would still result in positive net economic benefits for Alcan and El Paso (but not for Arctic Gas) and a delivered cost for gas that is not very much higher than other sources of energy. Consequently, there is little doubt that gas from the systems would be marketable.

- A postponement of the start-up of construction will reduce the present value of net economic benefits. The size of the reduction depends upon assumptions about discount rates and the future value of the gas. Postponement would reduce net benefits little, if at all, assuming a low discount rate and an increasing future value for the gas. This conclusion, however, does not consider that delay of gas delivery into a pipeline might increase capital costs and fuel requirements at the Prudhoe Bay field. This is discussed in a separate report on gas supply.

- A sensitivity analysis shows that net benefits would be reduced to near zero if any of the following occurs (10 percent discount rate and no growth in gas value)

- a delay during construction of greater than four years

- a construction cost increase of more than 100 percent

- a reduction in throughput from 2.4 BCFD to less than 1.2 BFCD

o An increase in the future value of the gas by 2 percent per year (above inflation) would increase the net benefits by about 60 percent.

o The net economic benefits are sensitive to assumptions about the discount rate. A rate of 6 percent instead of 10 percent almost doubles net economic benefits.

o In the short run there are larger employment impacts associated with the El Paso system but the relative impacts between systems are not as large as El Paso has presented before the FPC. Furthermore, any needed employment stimulation or job creation is more appropriately accomplished through monetary and fiscal policies.

o In a longer run time frame, there are no substantial differences in the macro economy in 1985 associated with any of the transportation systems.

A social decision to recommend one alternative Alaskan natural gas transportation system is in part an award of a natural monopoly. Comparisons of NNEB, cost of service, and macroeconomic impact are necessary but not sufficient elements of such a decision. The estimates and findings presented in this report must be used in conjunction with other important evidence on financing, environmental impacts, international relations, and national security to decide which system, if any, should be built.