COMMENTS ON THE

"DECISION AND REPORT TO CONGRESS ON THE ALASKA NATURAL GAS TRANSPORTATION SYSTEM"

ISSUED BY THE PRESIDENT

SEPTEMBER 22, 1977

FEDERAL ENERGY REGULATORY COMMISSION

OCTOBER 1977

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

October 12, 1977

TO THE CONGRESS OF THE UNITED STATES:

Pursuant to Section 8(f) of the Alaska Natural Gas Transportation Act, 15 U.S.C. §719f(f), the Federal Energy Regulatory Commission (FERC), having been delegated or having had transferred to it the authority which previously resided in the Federal Power Commission with respect to this matter, herewith submits to the Congress its comments on the "Decision and Report to Congress on the Alaska Natural Gas Transportation System", issued by the President on September 22, 1977.

We have reviewed the decision and support the President's determination that the completion of the Alcan project will benefit the public interest. In these comments FERC attempts to clarify and augment the discussion presented in the President's report and to outline for the Congress the additional procedural steps remaining to be taken by FERC prior to the actual commencement of construction of the pipeline - assuming the Congress acts affirmatively on the President's recommendation.

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Acting Chairman

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Acting Commissioner

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Acting Commissioner

* The Chairman did not participate in either the preparation of or the discussion of the Commission's comments on Chapter IX, "Western Leg." The Chairman sat on the Commission during consideration of this section of the Comments solely for the purposes of a quorum.

TABLE OF CONTENTS

	Page
SUMMARY AND OVERVIEW	1
I. Legal Requirement	1
II. Contents	1
III. Recommendation	2
COMMENTS ON CHAPTER I - "Desirability of an Alaska" Gas Project"	5
A. Gas Supply and Demand	5
1. Introduction	5
2. Prudhoe Bay Field	8
3. Canadian Gas	11
4. Other Gas Supply Supplements	15
5. Summary and Conclusion	17
B. Gas Processing Costs	19
1. Introduction	19
2. Need for Processing Gas	19
3. Water Injection Facilities	24
4. Costs of Processing Gas	26
5. Summary and Conclusions	32
C. Wellhead Pricing	34
COMMENTS ON CHAPTER II - "Financial Analysis"	36
I. Shippers	36
II. Producers and State of Alaska	43
III. Capital Requirements	44
IV. Reducing Uncertainties	45
V. Conclusion	45

Page

COMMENTS ON CHAPTER III - "Environmental and Socioeconomic Issues" 46

COMMENTS ON CHAPTER IV - "Economic Considerations" 48

I. Construction Cost Estimates 48
II. Tariffs 49
III. The United States-Canada Agreement 52
IV. Tracking or Flow-Through of Costs 54
V. Marketability of the Alaska Gas 55

A. Delivered Costs 55
B. Wellhead Price of $1.45 60
C. Wellhead Price of $2.00 61
D. Royalties In-kind 62
E. Level Tariff 62

COMMENTS ON CHAPTER V - "Safety, Reliability and Expansibility" 64

COMMENTS ON CHAPTER VI - "Organization of Federal Government Involvement After System Selection" 65

COMMENTS ON CHAPTER VII - "Impact on Competition in the Natural Gas Industry" 68

COMMENTS ON CHAPTER IX - "Western Leg" 70

GENERAL COMMENTS 72

I. Future Actions Under the Natural Gas Act 72
II. Waiver 74
III. Terms and Conditions 75
IV. Canadian Considerations 75

SUMMARY AND OVERVIEW

I. Legal Requirements

Section 8(f) of the Alaska Natural Gas Transportation Act, 15 U.S.C. §719f(f), provides:

> Within 20 days of the transmittal of the President's decision to the Congress under section 719e(b) of this title or under subsection (b) of this section, (1) the Commission shall submit to the Congress a report commenting on the decision and including any information with regard to that decision which the Commission considers appropriate . . . .

Pursuant to that direction, the Federal Energy Regulatory Commission (FERC or the Commission), having been delegated or having had transferred to it the authority which previously resided in the Federal Power Commission (FPC) with respect to this matter, 1/ herewith submits to the Congress its comments on the President's "Decision and Report to Congress on the Alaska Natural Gas Transportation System", issued September 22, 1977.

II. Contents

The President has recommended that a certificate be issued permitting Alcan and related applicants to construct

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1/ Subsection 705(b)(1), Department of Energy Organization Act, Pub. L. No. 95-91 (August 4, 1977).

and operate an overland pipeline from Prudhoe Bay, Alaska through Canada and back into the United States. The President's decision is consistent with the original findings of the FPC expressed in its May 1977 Recommendation to the President, with appropriate modification to conform to the accord reached between the United States and Canada, as expressed in the "Agreement on Principles." For this reason FERC has confined its comments to those matters of concern to the Commission and for the purpose of providing further amplification or explanation where it appeared necessary.

In these comments the Commission has neither restated the President's decision nor reiterated the extended discussion offered in support thereof. Procedurally, this report sets forth comments on Chapters I-VII, and IX of the Report, plus an additional section dealing with relevant matters not discussed in these chapters.

III. Recommendation

The Commission concurs in the President's choice of the Alcan project and agrees with the terms and conditions set forth by the President. These terms and conditions will serve the public convenience and necessity and are necessary adjuncts to any certificate issued pursuant to the Natural Gas Act. 2/ To the extent the President has indicated that further action is required by FERC, and assuming that the Congress approves the President's choice, the Commission is committed to ensuring an expeditious resolution of the certificate issues with which it must deal.

Several decisions with respect to final certification of the Alcan project remain within the jurisdictional responsibility of FERC. For example, the Commission must approve a tariff for the operation of the United States' portion of the pipeline system. This tariff will contain a variable rate of return provision, as the President required, but the exact parameters of that device, plus the other necessary components of a pipeline tariff, must be determined so that the applicants for certificates can arrange the necessary financing commitments. Moreover, the financing plan itself will be subject to Commission scrutiny and approval.

2/ 15 U.S.C. §§ 717, et seq.

In addition to tariff and financing issues, a wellhead rate for producer sales must be set either by the Congress through amendment to the Natural Gas Act or, failing that, by FERC. The costs of separating and processing the casing-head gas must be identified and allocated. There are additional technical and legal considerations that will require resolution. Furthermore, the organization and commencement of operation of the various intergovernmental and international relationships called for by the President's Report must be implemented.

COMMENTS ON CHAPTER I
"Desirability of an Alaska Gas Project"

A. Gas Supply and Demand

1. Introduction

The Report reaches several fundamental conclusions with respect to Alaska gas:

(1) The addition of Alaska gas to domestic production will make a substantial contribution toward closing the gap between natural gas supply and demand;

(2) The principal impact of Alaska gas on U.S. natural gas supply and demand will be to help reduce natural gas shortages; and

(3) Even with Alaska gas, the United States may need additional supplemental sources of gas supply to meet demand.

The Federal Energy Regulatory Commission fully agrees with and supports these conclusions. There are, however, certain portions of the Alaska gas supply discussion which we believe may benefit from further elaboration.

Also discussed is the Report's suggested "pre-delivery" plan for Alaska gas, which was not considered in the proceedings before the FPC. The plan is an outgrowth of a proposed gas pipeline to the Mackenzie Delta, as discussed in the Canadian National Energy Board (NEB) decision of July 4, 1977. This plan was also one of the subjects of the recent negotiations between the United States and Canada relating to the gas pipeline project.

Under the "pre-delivery" plan for Alaska gas, early construction of the southern portion of the Alcan system would be required. According to the Report, the probable benefits of the plan would be increased exploration activity in Canada, resulting in early increased gas exports and possible long-term increased exports from Canada. The "pre-deliveries" of Alaska gas would be repaid to Canada by reduced export commitments in the late 1980's or by time-swaps for Alaska gas. We endorse the "pre-delivery" plan conceptually, noting, however, that many details remain to be finalized.

The "pre-delivery" plan has the benefit of expediting the time at which northern gas could be made available to the markets in the lower 48 states. It also has the advantage of encouraging increased exploration and development activities in Canada, with the possibility of increased exports. Of course, care must be taken to insure that the short-term availability of these increased supplies does not diminish incentives for needed conservation or reduce the speed with which low priority users shift away from natural gas. The desirability of the "pre-delivery" plan will depend on the arrangements made with Canada, the distribution of the gas among pipelines and end-users, a determination of which types of pricing methodology will be employed, and the future burdens repayment may impose.

The Commission also offers clarifying comments on the level of gas deliveries to be expected from the Mackenzie Delta, infra pp. 11-13. Even with increased exploration in Canada's frontier regions, other measures will also be required to improve the energy resource bases of our two countries.

2. Prudhoe Bay Field

The Report states that "proved saleable gas reserves in the Main Pool" of the Prudhoe Bay Field are 20.6 to 22.8 Tcf (Rep. 89). Review of information made available subsequent to the FPC's Recommendation supports this conclusion. These levels of saleable reserves are predicated upon estimated gas-in-place volumes of 40.4 Tcf and 42.8 Tcf respectively, 3/ reflect a twenty-four percent "shrinkage factor", 4/ and rely on the assumption that seventy percent of the gas reserves can be produced during the first

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3/ The 40.4 Tcf (Trillion Cubic Feet) is based upon a study prepared by H. K. Van Poollen and Associates for the Dvision of Oil and Gas Conservation (DOGC), Department of Natural Resources, State of Alaska. The 42.8 Tcf is based upon data presented by the three largest field operators (ARCO, BP, and EXXON) at the Prudhoe Bay Unit Hearings held before DOGC in Anchorage on May 3, 5, and 6, 1977.

4/ The FPC Recommendation estimated the gas "shrinkage factor" to be 26%. This factor was also adopted by the State of Alaska, infra note 5. The shrinkage factor reduces the volume of gas produced to account for CO_2 removal, field use, and conditioning gas for transportation. See FPC Recommendation, pp. III-14, III-15. See also, "Report of the Working Group on Supply, Demand, and Energy Policy Impacts of Alaska Gas," July 1, 1977, pp. 10-11. This report was developed by FEA, ERDA, USGS, and the Departments of Commerce, Transportation, and Treasury.

twenty years a gas pipeline from Prudhoe Bay Field is available. This estimate of "proved saleable gas reserves" is appropriate and consistent with Commission calculations. Indeed, the potential may be greater if one looks to the representations made by the producers to the State of Alaska.

The Prudhoe Bay Field operators received approval from the State of Alaska for their proposed reservoir management plan. 5/ This plan is predicated upon a gas-in-place volume of approximately 42.8 Tcf. The producers also project that seventy-five to eighty percent of the in-place gas may ultimately be recovered.

Assuming the reservoir can be managed to allow seventy-five to eighty percent gas recovery efficiency, the total saleable gas reserves to be realized from the Prudhoe Bay Field could be approximately 25 Tcf (42.8 Tcf x 80% recovery efficiency x 74% after shrinkage).

5/ "Conservation Order Number 145, Prudhoe Bay Field, Prudhoe Bay Oil Pool," July 1, 1977, issued by Division of Oil and Gas Conservation, Department of Natural Resources, State of Alaska.

The Report also states that "Prudhoe Bay production at 2.4 Bcfd (billion cubic feet per day) will include production from other reservoirs which have been identified in the field, the Kuparuk and Lisburne" (Rep. 89). The reservoir management plan approved by the State of Alaska contemplates that 2.0 Bcfd and possibly as much as 2.5 Bcfd will be delivered from only the Main Area Sadlerochit reservoir. 6/ Production from the "West" or "Eileen Area" of the Prudhoe Bay Oil Pool, which Pool includes the Sag River and Shublick reservoirs in addition to the Sadlerochit reservoir, and from the Kuparuk River Oil Pool and the Lisburne Oil Pool could result in additional gas deliveries. 7/

6/ See FPC Recommendation, pp. III-19 to III-21. See "Report of the Working Group on Supply, Demand and Energy Policy Impacts of Alaska Gas," July 1, 1977, pp. 17-18. The Prudhoe Bay Field is divided into what is referred to as "The Main Area" and the "West" or "Eileen Area." The Main Area portion of the Sadlerochit reservoir contains approximately 84 percent and 93 percent of the total field's gas cap and oil zone hydrocarbons, respectively.

7/ See FPC Recommendation, pp. III-8 to III-10 for description of various pools and reservoirs in the Prudhoe Bay Field.

These additional deliveries will most likely be small, however, in comparison to the deliveries from the Main Area Sadlerochit reservoir.

3. Canadian Gas

The Report discusses two sources of Canadian gas supply: (1) the projected deliveries of gas from the Mackenzie Delta area and future exploration and development in the Mackenzie Delta, and (2) the increased level of gas exports from the traditional gas supply sources in Alberta. The Report concludes that construction of the Alcan project will stimulate exploration in both the Mackenzie Delta area and Alberta. As a result of the expected exploration, the "possibility of obtaining additional volumes of Canadian gas in future years will be enhanced." (Rep. 93).

Subsequent to submission on May 2, 1977, of the FPC's Recommendation to the President, the Canadian National Energy Board (NEB) issued on July 4, 1977, its decision on the northern pipeline project. The NEB found that absent a project which provided Canadians access to their frontier gas reserves, Canada might not have sufficient gas supplies to fulfill existing gas export licenses to the United States. Access to frontier gas reserves would permit gas exports to continue at least at their present level.

During negotiations between the United States and Canada concerning a gas pipeline project, the possibility was discussed of effectively making Alaska gas available to the United States through pre-delivery of Canadian gas under existing export licenses. The Report discusses this possible arrangement as follows:

> ...The southern portions of the Alcan project could be constructed first, and deliveries of excess gas from Alberta could reach as much as 1.1 Bcfd by the winter of 1979-1980. As currently proposed, the pre-deliveries would be repaid by reduced export commitment in the late 1980's, or by time-swaps for Alaska gas. (Rep. 92).
>
> ...pre-delivery would make extra gas available over the next few years when the Nation faces serious and immediate natural gas shortages, prior to the time when supply stimulation and demand reduction measures under the National Energy Plan have had any effect in helping bring natural gas supply and demand back into balance. (Rep. 93).

Details remain to be worked out, of course, between producers and purchasers in Canada, as well as export-import agreements between the United States and Canadian companies.

The Report also states that "a project which brings a major pipeline effectively within 500 miles of the Mackenzie Delta region should stimulate further exploration activity there." (Rep. 93). In its Recommendation, the FPC found:

> ...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 FERC concurs that the Alcan project should provide increased exploration incentives in both the Mackenzie Delta area and Alberta. Benefits should accrue to both the United States and Canada as a result of any increased exploration in Canada. Through continued exports under existing contracts and possible "pre-deliveries" of Alaska gas as a result of early construction of the southern portions of the Alcan project, the United States would be assured maximum availability of Canadian gas in the near future. The development and export of gas should provide a stimulus for the Canadian economy, as well as for the United States economy. Increased exploration could also result in long-term improvement in Canada's energy resource base, which should increase the likelihood of longer-term gas supplies being made available to the United States. The availability of these supplies should not, however, be used to forestall efforts to increase energy conservation, as well as to encourage low priority users to shift away from the use of natural gas.

4. Other Gas Supply Supplements

The Report discusses, in addition to gas to be delivered through the Alcan system, two other "economically attractive means to supplement traditional domestic supplies by 1985." (Rep. 89) The first is to accelerate Outer Continental Shelf leasing in the Gulf of Mexico, and the second is to import gas from Mexico. Accelerated leasing offers the potential for early increases in gas supplies. As to possible Mexican imports, there is presently pending before FERC 8/ a recently filed application to import substantial quantities of gas from Mexico. Deliveries of approximately 50,000 Mcfd (thousand cubic feet per day) through existing facilities could commence as early as late 1977. After completion of new pipeline facilities in the Republic of Mexico and in the United States, imports from Mexico could increase as follows:

Year	Volumes (Bcfd)
1979	0.7
1980	1.3
1981	1.4
1982	1.5
1983	1.6
1984	1.7
1985	1.8
1986	2.0

8/ Under the Department of Energy Organization Act, Public Law No. 95-91 (August 4, 1977), jurisdiction over natural gas imports under Section 3 of the Natural Gas Act is transferred to the Secretary of Energy (§402(f)).

This projection of deliveries from Mexico is slightly different from the projection of 1.0 Bcfd not before 1980 and 2 Bcfd by about 1982 stated in the Report. (Rep. 227) The projection stated above is based upon information recently filed with FERC. 9/ These differences should not affect the conclusions reached in the Report, and they are not controlling in our concurrence and support of the overall conclusions of the Report.

FERC is in full support of the Report's conclusion that, in addition to Alaskan gas, the United States may increasingly need supplemental sources of gas supply to meet demand. As the Report points out, supplemental sources include:

- geopressurized aquifers containing methane
- Devonian shale
- deeper, tighter formations
- coal gasification
- imports of liquefied natural gas (LNG)
- synthetic natural gas (SNG) 10/

9/ The above projection of imports is based upon data contained in applications filed with FERC to construct facilities to handle the subject imports. The projections of possible imports from Mexico of "as much as 0.5 Tcf per year by 1985 and 0.7 Tcf per year by 1990" (Rep. 89) may be too low, based upon information available to us. This should not be viewed, however, as a prejudgment of any issues involved in proceedings before FERC.

10/ Given the present imbalance between domestic crude oil production and total demand for products derived from crude oil, the feedstock to most domestic SNG plants would very likely require imported crude oil or oil products.

5. Summary and Conclusion

Most of the comments in the preceding discussion are offered as clarification to assist in analyzing the Report. Other comments have been made on proposals which have surfaced subsequent to the FPC's May 2, 1977, Recommendation to the President. Neither newly available information nor events occurring subsequent to our submission of the Recommendation change the central gas supply conclusion reached therein:

- The Alaska North Slope proved gas reserves and future gas potential justify a gas transportation system.

We support the Alaska gas "pre-delivery" plan conceptually. We note, however, that many details remain to be worked out between Canadian producers and purchasers and between Canadian exporting and United States importing companies.

We concur with the views expressed in the Report that, even with Alaska gas, the United States may need additional supplemental sources of gas.

We also concur in and support the views and conclusions related to gas supply and demand expressed in the Report:

> The most optimistic 1985 projection for U.S. domestic production of gas is 17.5 Tcf without Prudhoe Bay gas. This is 15 percent less production than in 1970. Yet during this same period - 1970 to 1985 - it is estimated that total energy demand will increase by over 40 percent. Further, a more pessimistic but still plausible estimate of the domestic resource base would reduce 1985 production of gas by an additional 0.9 Tcf per year.
>
> On the demand side, it is apparent that this Nation could use all the reasonably priced natural gas it can produce. Even with the ambitious coal conversion program proposed earlier this year by the Administration, projections indicate that Alaska natural gas will be needed to meet demand in the coming decade. (Rep. 88)

B. Gas Processing Costs

1. Introduction

Gas processing will be required at the Prudhoe Bay Field to condition the gas for transportation. This process involves removal of CO_2, removal of liquefiable hydrocarbons as required for dew point control, removal of moisture, and compression and cooling of the gas to pipeline pressure and temperature specifications. The following comments discuss the need for processing the gas, the requirement for water injection to maintain reservoir pressure if gas is sold rather than utilized for pressure maintenance, and processing cost considerations.

2. Need for Gas Processing

Chapter III of the FPC Recommendation to the President contains a detailed discussion of the Prudhoe Bay Field, its geology, reservoir content, and the reservoir management plan to be implemented. 11/ There is no need to repeat that detailed discussion. However, the following discussion should assist in relating the gas processing operation to other aspects of the field.

11/ The reservoir management plan discussed in the Recommendation has been approved by the State of Alaska, *supra* notes 4 and 5.

The Prudhoe Bay Field is the largest petroleum accumulation discovered on the North American Continent. The field contains several oil reservoirs in which over 20 Bcf of saleable gas reserves and over 9 billion barrels of recoverable oil reserves exist. Some of the gas is in solution with the oil. Gas in excess of the solution capacity of oil has accumulated in the higher elevation of the reservoir and forms a "gas-cap."

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. Moderate expansion of the gas cap into the oil zone during the early years of oil production will eliminate or greatly minimize oil migration into the gas cap after gas sales commence.[12/]

12/ A large portion of any oil that migrates to the gas cap would be unrecoverable. For detailed discussion, *see* FPC Recommendation, pp. III-4 to III-24. *See also*, "Report of the Working Group on Supply, Demand and Energy Policy Impacts of Alaska Gas", pp. 11-13.

Therefore, from a production standpoint, the gas should not be viewed as a by-product which must be sold either during the initial years of oil production or thereafter.

The "Report of the Working Group on Supply, Demand and Energy Policy Impacts of Alaska Gas"[13/] estimated that "about 80% of gross income from Prudhoe Bay's Main Pool will be derived from oil production, dependent obviously, on oil and gas well head prices." This estimated relationship between the gross value of oil to total production from the Prudhoe Bay Field is highly speculative at this time, as the statement indicates. The estimate does, however, give an indication of the weight that considerations affecting principally oil production could have on the operations of the field.

In the initial years of the Prudhoe Bay Field, the gas produced will be associated gas. Gas will not be produced initially from the gas cap. Prior to the

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13/ *Supra,* note 4.

commencement of gas sales, the produced gas will be processed to remove liquefiable hydrocarbons to the extent necessary to make the gas available for field use and to allow compression of the gas for reinjection into the reservoir.

After gas sales commence, further processing of the gas will be required. The produced gas contains approximately twelve percent CO_2. Carbon dioxide has no value as a fuel. Its removal on the North Slope is required so that only useful ingredients are shipped through the pipeline system. Furthermore, operational problems could occur in the transportation of gas if CO_2 were present.[14/]

Conditioning the gas for transportation will also include removal of liquefiable hydrocarbons as required for dew point control (i.e., removal of hydrocarbons which may condense in the transportation system and cause operating problems). Compression and cooling of gas would also be required to meet pipeline pressure and temperature specifications.[15/]

14/ CO_2 could form "dry-ice." Also, CO_2 could combine with water to form carbonic acid, a mildly corrosive agent.

15/ The first compression station on the Alcan pipeline system would be at Milepost 75. *See* Report p. 17. Also, the gas has to be chilled below 32° F to prevent degradation of the permafrost. *See* Decision, pp. 14-15.

The amount of liquids to be recovered from the produced gas is substantial, useful, and valuable. A technical report filed with the State of Alaska by the major interest owners in the Prudhoe Bay Field (ARCO, BP, EXXON, and Sohio) in support of their proposed reservoir management plan states:

> A gas cap gas condensate yield of about 35 barrels per million cubic feet of separator outlet gas is expected initially from the separator facilities located at the flow stations (gathering centers). In addition, it is expected that once gas sales begin, 10-15 barrels of gas liquids per million cubic feet of separator outlet gas will be extracted at the gas sales conditioning plant to make the gas acceptable for delivery into the gas pipeline.
>
> Gas pipeline specifications are not currently known and final specifications may increase or decrease the volume of liquids which must be extracted from the gas to prevent condensation in the pipeline. Regardless of the final gas conditioning requirements, all liquid extracted will be used without waste; either to displace fuel gas or to be transported through the oil pipeline. 16/

16/ Exhibit ALA-33 filed in proceedings before FPC, p. 16.

3. Water Injection Facilities

Another important feature in analyzing the gas processing operation is the possible requirement of large-scale facilities for water injection. If gas is sold and not reinjected into the reservoir, injection of water from an extraneous source, in addition to reinjecting produced water, may be required. The producers estimate that the cost of large-scale extraneous water injection facilities could exceed one billion dollars.

The producing mechanisms available to the Prudhoe Bay Field (i.e., depletion drive in the oil zone, gas cap expansion, gravity drainage, and water drive) were discussed in detail in the FPC Recommendation to the President. 17/ A strong, efficient natural water drive may not occur in the Main Area Sadlerochit reservoir. Without a strong natural water drive, the rate at which gas is produced and sold, as opposed to reinjected, will determine the depletion rate of reservoir energy needed to produce the oil.

17/ *See* especially pp. III-15 to III-21 of the Recommendation.

In order to make sufficient gas available over the long-term to support a gas pipeline project, large expenditures by the producers may be necessary to implement an extraneous source water injection program. Three to five years of actual production history will be required to analyze the performance of the petroleum reservoir and to quantify the effect of the aquifer on production performance. Based upon such production history, the producers may implement an extraneous source water injection program when the additional recovery prediction of 3% to 7% of the original oil in place from such operation is verified. It has been estimated that such an extraneous source water injection program could cost over $1 billion. 18/

We are unable at this time to describe precisely how the costs of water injection facilities should be balanced against the costs of gas processing facilities, but some consideration is required. This view is expressed, however, in the context of not yet knowing the final course of reservoir management, the extent of the facilities required

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18/ Exhibit ALA-33 in FPC Proceedings, pp. 6, 29.

to implement the required operations, and the provisions of the purchase gas contracts. 19/

4. Costs of Processing Gas

Various estimates of the costs of processing the gas have been made. The Report indicates that processing costs that may be assignable to gas and not to extracted liquids are in the range of 0¢ to 30¢ per Mcf. The upper limit of this range represents the assignment of 100% of the processing costs to the processed gas stream, while the lower limit assumes that all of the processing costs should be borne by the extracted liquids.

In commenting on the processing costs, we discuss first the total costs of the gas processing operations, and second the considerations affecting the portion of processing costs that should be borne by gas consumers.

19/ These expressed views should not be construed as prejudging any proper showing made in a proceeding before FERC.

The estimated cost of the facilities required for separating the produced fluids into liquids and gas, gathering the gas, and conditioning the gas for transportation were presented in the FPC proceedings.20/ The costs estimated by the producers were:

Facilities	Estimated Costs 1975 Dollars (Million) Capital Costs	IDC 21/	Total
Gas Facilities at Gas-Oil Separation Centers	429	98	527
Gas Gathering Facilities	49	8	57
Gas Conditioning Plant	966	286	1252

20/ Transcript p. 19,497.

21/ Interest During Construction.

Caution must be exercised in responding to any of the above costs, since they were made without the benefit of the final pipeline specifications. Additionally, the costs were also estimated without the benefit of producer/purchaser gas sales contracts. In the absence of definitive gas purchase contracts, uncertainties still remain as to whether the purchasers will have any obligations for the gas gathering and processing costs. Uncertainties also remain as to the handling of revenues attributable to the extracted liquids. Furthermore, it is still unclear whether the gas purchase contracts would provide additional gas processing rights after the gas leaves the North Slope of Alaska. The gas purchase contracts to be negotiated between the producers and gas purchasers should address these issues.

Gas/oil separation facilities are required to make the oil saleable, and they would be required whether the gas were sold, used for field operations, or reinjected into the reservoir to sustain oil production. Based upon the information available to us at the present time, it appears that the costs of gas/oil separation facilities would not be borne by the gas consumer. 22/

22/ The producers submitted only limited cost information in the FPC proceedings. The nature and function of the "gas facilities at gas-oil separation centers" are not entirely clear from the data available to us at this time.

We make this statement in the context of gas/oil separation facilities used in a normal oil production operation, recognizing that at least a portion of the gas-liquid separation facilities that will be necessary to handle fluids from the gas cap may be properly allocable to gas.

A portion of the gas gathering facilities may properly be borne by the gas consumer.23/ In some cases, where the gas is processed by producers subsequent to gathering by a pipeline company, the FPC allocated field compression and gathering costs between residue gas ultimately reaching the pipeline and extracted liquids retained by the producers. In other arrangements, where the producers process the gas subsequent to gathering and/or transportation by a pipeline company a transportation charge to the producer by the pipeline was approved.

Many of the gas purchase and transportation arrangements have become complex in recent years, largely because of the extensive facilities required to tap some of the

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23/ In past producer rate proceedings the FPC approved methodologies for non-associated gas which permitted allowances for gas gathering facilities. See, for example: Opinion No. 699, issued June 21, 1974, Docket No. R-389-B, mimeo pp. 93-94. ___FPC___. See also, Opinion No. 699-H, issued December 4, 1974, Docket No. R-389-B, mimeo pp. 36-38. ___FPC___.

offshore and more remote onshore gas supplies. Most arrangements, by necessity, have to be reviewed individually. Therefore, we would have to review the specific producer/purchaser gas sales contracts before an informed judgement as to the level of Prudhoe Bay Field gas gathering costs that should be borne by the gas consumers can be made.

In producer rate proceedings before the FPC the gathering and conditioning costs have been small in relation to other costs. Gas gathering and conditioning costs for the Prudhoe Bay Field, however, will be larger. A final determination of processing costs must consider that the gathering and conditioning operations and costs for the Prudhoe Bay Field may not be comparable to the operations and costs in the lower 48 states. Producers point to the unusually high delivery pressure required at the Prudhoe Bay Field. This high pressure is reflected in the fact that the first compression station is at Milepost 75 of the Alcan pipeline (Rep. 17), rather than closer to or at the field.

The gas must be chilled to below 32°F to prevent degradation of the permafrost regime. 24/ Operation of

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24/ See Decision, pp. 14-15 for discussion of the occurrence and distribution of permafrost.

the pipeline system in a chilled state also imposes stringent requirements on the inlet gas for low CO_2 content and low hydrocarbon and water dew point levels. We appreciate the size, complexity, and costs (at least based upon available information) of the gas conditioning facilities; however, a significant function of the processing facilities apparently will also be the removal of liquefiable hydrocarbons. Therefore, absent knowledge of the contractual arrangements for disposing of the extracted liquids, we cannot at this time be definitive as to processing costs.

Several other important features should be considered in determining the amount of gas processing costs that should be borne by the gas consumers. Some of the hydrocarbons liquefied at the processing plant may be reinjected into the gas stream. The Alcan system actually contemplates this type of operation, which results in Alcan transporting gas with a heating value of approximately 1138 Btu per cubic foot. This is greater than the typical city-gate gas heating value in the contiguous states of approximately 1030 Btu per cubic foot.

However, it is not clear at this time whether the producer/ purchaser gas sales contracts would provide for further processing of gas by the producers after the gas leaves the North Slope of Alaska. Further processing could occur and still allow gas with a heating value slightly in excess of 1000 Btu per cubic foot to be delivered to the ultimate gas consumers. If one of the purposes and results of the processing operation were that relatively high Btu gas would be made available to the pipeline on the North Slope in exchange for the producers retaining further gas processing rights elsewhere on the pipeline system, this arrangement should be considered in determining the level of gas processing costs to be borne by the gas consumers.

5. Summary and Conclusions

The gas conditioning operations to be conducted at the Prudhoe Bay Field are required to make the gas suitable for transportation. These conditioning operations will also make additional liquids available for use or sale.

Based upon information available at this time, it is our view that the cost of the gas-oil separation facilities probably should not be borne by the gas consumers, since gas-oil separation facilities are a necessary part of the oil production operations and are required in order to make the oil saleable. The facilities would be required, based on our understanding of the proposed field operations, whether or not gas sales were made.

We cannot at this time state definitively our views on gas gathering facilities costs. A portion of these costs may be properly assignable to the liquids extracted in the processing operation; and it is the gas purchase contracts between the purchasers and producers that normally determine the processing rights and obligations and establish the ownership of the extracted products. These contracts have not as yet been executed.

The cost of the gas conditioning plant should be evaluated in the context of the plant's actual operations and the provisions established by the gas purchase contracts. In determining the amount of the gas conditioning plant costs to be borne by gas consumers, considerations should include the quality of the gas made available to the pipeline (particularly the heating value, pressure and temperature), the ownership of extracted products, and whether further processing of the gas will occur after it leaves the North Slope of Alaska.

If gas is sold rather than reinjected into the reservoir, a large-scale source water injection program may be required to sustain reservoir energy needed for oil production. Several years of actual production history are needed to evaluate the reservoir performance and quantify the extent of natural water drive. The producers estimate the source water injection project would cost over one billion dollars. In determining the amount of processing costs to be borne by the gas consumer, some balancing may be necessary to give consideration to the level of possible expenditures that may be required for a large-scale source water injection project.

C. Wellhead Pricing

The wellhead price applicable to the Alaska sales has not yet been determined. The rate will be set by Congressional action to amend the Natural Gas Act or, failing that, by the FERC. The President's Report recommends that Alaskan gas be priced according to the proposed National Energy Plan, which calls for a base rate of $1.45 per million Btu (for old gas under a new contract). The Report indicates that, at a wellhead price of $2.00 per Mcf or higher, the project may not be capable of being financed. (Rep. 46). While the Commission does not take a position on the proper rate to be employed 25/, the marketability of the gas must be considered in any eventual price consideration.

25/ If Congress does not set the rate, then FERC must convene a ratemaking proceeding that will determine on-the-record a just and reasonable rate pursuant to the dictates of the Natural Gas Act. Thus, if the Commission were to take a position now as to what the proper rate should be, and if FERC were to have set the rate itself, then the Commission would have placed itself in the untenable position of having prejudged the outcome of a proceeding that must be decided solely on the basis of the record evidence adduced.

COMMENTS ON CHAPTER II
"Financial Analysis"

The President's Decision and Report to Congress requires that the Alcan project be financed privately. The risks involved in the project are to be borne by those entities that will directly benefit therefrom, and those entities will be compensated for incurring the risks. In addition, the gas company sponsors, the producers, and the State of Alaska will also be direct financial beneficiaries of the Alcan system, and, since they have the creditworthiness to assist in the successful financing of the Alcan system, as the Report suggests, their participation would be of assistance. FERC concurs in this approach to the financing question, although finalization of the specific financing plan is a matter that must be decided by FERC in the future.

I. Shippers

The President's Decision at page 38 requires that the Alcan Pipeline Company and the Northern Border Pipeline be "... open to ownership participation by all persons without discrimination, except producers of Alaskan natural gas." Nonetheless, it is contemplated that the majority of the equity in Alcan and Northern Border will be held by the shippers. Moreover, the Canadian equity is expected to be provided by the four companies supporting the project in Canada (Rep. 111).

The President's Report states that the equity invested in the project should be at risk and that the sponsor companies would have to honor any equity commitments in the event of noncompletion. Equity investors in business ventures normally incur these risks, and it is appropriate for the sponsor investors in the Alcan project to bear such risks. In addition, the sponsor companies will have to make provision for the equity portion of any funds needed to cover cost overruns.

Potential lenders to the project will analyze the sponsor companies to determine whether or not the sponsors have the financial strength to provide the initial equity capital as well as any additional equity needed to cover potential cost overruns. The Department of Treasury was the lead agency in developing the "Report to the President, Financing an Alaskan Gas Transportation System," which was released on July 1, 1977. The Report concluded that the sponsor gas transmission companies have the financial capability to provide the equity capital, including equity capital which may be needed for cost overruns.

The oil companies that sponsored the Alyeska oil pipeline contributed the equity to that project and, in addition, guaranteed the debt that was incurred to construct the line. A similar debt guarantee may be necessary to secure financing of the Alcan project. For this reason, the President's Decision invites the producers and the State of Alaska to provide debt guarantees during the construction period of this project.

The President's Report states at page 120 that the Alcan financial advisors and sponsors believe that the project could be financed without an "all events" tariff, without consumer noncompletion guarantees, and without Federal financial assistance. All that is contemplated is a tariff that would provide for the maintenance of debt service in the event of a service interruption. This type of provision should provide the lenders with sufficient assurance that the debt would be serviced even in the event of a service interruption.

The "variable rate of return" concept proposed in the President's Decision has a great deal of merit. While the details will have to be worked out respectively by the FERC and the NEB, it appears that an equitable method of providing the proper incentive to control construction costs would be to arrange accountability on the basis of project segments. In other words, the sponsor investors responsible for constructing various segments (Alcan, Canadian Segments, Northern Border and Western Leg) of the project would be rewarded or penalized in terms of return based on the cost of constructing their segment relative to the estimate for that segment.

To provide a basis for further consideration of this issue, the following illustrative example is offered as to how a variable rate of return may be structured to accomplish the President's objectives. Because the variable rate of return is intended to provide a cost control incentive, the design of a variable rate schedule would begin with the rates allowed on increments of cost. Each increase of 10% over estimated costs would yield a lower rate of return than preceding increments. Naturally, the overall rate declines but the incentive operates through the declining rate on cost increments. The design of the variable rate of return begins, therefore, with the rates on increments as illustrated in Column 3 of Table I. Selection of an appropriate rate for the case when actual and estimated costs are equal then provides the basis for calculating the overall rate at other cost levels. This rate, if selected according to the usual regulatory principles, should be adequate to attract equity funds for the project. Assume a 15% rate is selected. If the 15% rate can be earned on each increment of costs, there would be no disincentive to hold down costs and, indeed, the open ended availability of a 15% rate of return may actually create economic incentives to increase costs. Therefore, to avoid creating this incentive, the highest incremental rate, 13.5% in the table, should be less than the overall rate, 15%, allowed when actual and estimated costs are equal.

How do these concepts relate to sharing of overruns and underruns by equity investors and rate payers? When the rate of return is variable, the notion of cost sharing can be formulated in several ways. For illustrative purposes, the idea of equivalent rate base is introduced, which is the rate base necessary to earn the total return given by the next higher overall rate of return. In Table I, for example, when actual costs are 120% of estimated, with a rate of 13.88%, a rate base of 115.2 is necessary to earn the same total return which results from a rate of 14.45% when actual costs are 110% of estimated. The declining rate is equivalent then to losing 4.8 of the rate base increase of 10, the total return remaining the same, and the equity share of the overrun is 48%. With underruns, equivalent rate base is gained, and the equity share of the underrun is proportionate to the gain.

A variable rate of return can be designed in a number of different ways. For example, it can be designed to provide different rates of return for different increments of cost or it can be used to apportion between investors and rate payers varying return depending upon the extent of cost overruns and underruns. The bottom section of the Table on page 42 illustrates the principal alteration that results from this latter approach. If it is desired that equity holders obtain a larger share of larger underruns, then the incremental rates of return decline with larger underruns (greater savings relative to the 100% case), and the overall rate of return increases more rapidly than before.

TABLE I

ILLUSTRATIVE VARIABLE RATE OF RETURN

(1) Costs Actual ÷ Estimated (%)	(2) Equity Rate of Return (%)	(3) Incremental Rate of Return (%)	(4) Fquivalent Rate Base (%)	(5) Equity Shar of Increment Overrun (Underrun)
70	16.29			
		13.5	71.5	(.15)
80	15.94			
		12	82.3	(.23)
90	15.50			
		10.5	93	(.3)
100	15.00			
		9	106	.4
110	14.45			
		7.5	115.2	.48
120	13.88			
		6	124.3	.57
130	13.27			
		4.5	133.4	.66
140	12.64			
		3	142.4	.76
150	12.00			
		1.5	151.2	.88
160	11.34			
		0	160.1	.99
170	10.68			
		0	169.9	1.01
180	10.08			
		0	180	1.0
190	9.55			
		0	190.2	.98
200	9.08			

70	17.88			
		6.6	76	(.6)
80	16.74			
		7.74	85	(.5)
90	15.50			
		10.5	93	(.3)
100	15.00			

The capital cost estimates that will be used as the basis for determining the "variable rate of return" for the U.S. segments of the Alcan project will be those estimates submitted to and accepted by the FERC immediately prior to certification. When comparing these estimates to the capital cost estimates filed by Alcan with the FPC on March 8, 1977, and in deciding whether to issue a certificate, the President's Report requires FERC to determine whether the new estimates, as adjusted, "materially and unreasonably exceed" the old estimates (Rep. 36).

II. Producers and State of Alaska

If producers and the State of Alaska guarantee the debt during the construction period, the risk to the equity holder is reduced. Naturally, this reduced risk must be reflected in a lower allowed return on common equity. There are substantial financial rewards available to the producers and the State from the sale of Alaskan gas (Rep. 117-119), and it is contemplated that these incentives will induce these parties to proffer a debt guarantee program. As of this time, however, there are no such commitments from the producers or the State.

III. Capital Requirements

While the capital requirements for financing the Alcan project are substantial, the capital markets can accommodate the project's needs. The United States capital markets have the capacity to provide the estimated $8,460 million to be raised in those markets. The amount of capital ($1,842 million) that the Alcan project plans on obtaining from the Canadian markets is larger in relation to the size of the Canadian markets than the amount of money that is needed from the U.S. markets is in relation to the size of the U.S. markets. If it appears that the capital required from the Canadian markets may not be available in a timely fashion, funds could be obtained from the international or U.S. markets. While it is impossible to determine at this time what the cost of capital will be for the Alcan project, the cost of capital may be higher for those funds obtained from the Canadian markets. Finally, studies conducted by the Department of the Treasury and the FPC staff indicated that the sponsors, the producers, and the State of Alaska have the financial ability to finance the project as outlined in the President's Decision.

IV. Reducing Uncertainties

It is correctly stated in the President's Decision that the uncertainties surrounding the Alcan project should be reduced to a minimum by the Federal Government. One area of uncertainty which must be resolved is the issue of whether FERC will allow customers to make minimum bill payments in the event of lengthy service interruptions.[26] Moreover, the Federal Inspector mechanism contemplated in the President's Report, by establishing a method for judging the prudence of costs incurred on a current basis, should provide investors as well as consumers with greater confidence that the Alyeska experience will not be repeated.

V. Conclusion

The Alcan project could be and should be financed privately, without Federal assistance. The sponsor gas companies and their financial advisors have stated that private financing is possible and that they are willing to proceed on that basis. The potential financial benefits to the producers and the State of Alaska should afford sufficient incentive to attract their participation in the financing of the Alcan project.

26/ This issue may also present a problem at the state level.

COMMENTS ON CHAPTER III
"Environmental and Socioeconomic Issues"

It is accepted that the Alcan proposal is the superior Alaskan Natural Gas Transportation System from an environmental standpoint. The Commission strongly supports, on environmental grounds, the President's Decision to approve Alcan's route, and concurs with the conclusion of the Council on Environmental Quality that the environmental impact statements are legally and factually sufficient to support the President's choice of an applicant and a route. Moreover, along with our support of Alcan based on environmental concerns, we emphasize that steps can be taken to further minimize environmental impact. These consist primarily of: 1) elimination of any unnecessary construction; 2) minor route modifications to avoid environmentally sensitive areas; 3) additional special studies to provide guidance on environmental planning, safety and route selection; and 4) use of existing Trans-Alaska Pipeline System (TAPS) right-of-way and construction areas where prudent and feasible. 27/ All of these steps can be incorporated in the terms and conditions of a final certificate.

27/ One of the principal advantages of the proposed Alcan route is its use of existing utility and transportation rights-of-way -- the utility corridor concept. The Commission wishes to point out, however, that the juxtaposition of transmission facilities is not necessarily without its own problems. Adequate safeguards must be taken along the TAPS right-of way to avoid construction accidents which may have serious consequences, and minor modifications to the route selection may yet be required to minimize environmental and socioeconomical impacts.

COMMENTS ON CHAPTER IV
"Economic Considerations"

I. Construction Cost Estimates

The estimation of costs due to construction delays and overruns is extremely difficult to make. The base from which almost all discussions of construction costs of ANGTS projects start are the same, the July 1975 cost estimates submitted to the FPC by the applicants. Divergence from these estimates results almost exclusively from changing the assumptions utilized.

The factors discussed in the Report (pp. 136-138) have caused overruns in the past and may be expected to do the same to Alcan. While mechanisms, such as a variable rate of return and a strengthened Federal Inspector, will help minimize this potential, it is likely that actual cost experience will exceed the estimated costs of this project. The question, of course, is by how much. Based on our analysis of additional information available to the President, we would agree with his estimate of the overrun potentials of the Alcan project.

II. Tariffs

The President's Report addresses some of the issues involved in designing the tariffs for the gas transportation system, but relies upon the FERC for final approval. Since the specific provisions of the tariff have not been finalized, in order to preserve the Commission's decision-making flexibility, it can only state at this time that the Report sets several general guidelines which the Commission will follow in exercising its regulatory authority to set tariffs.

The President's Report clearly contemplates that an acceptable tariff must include a variable rate of return, keyed to the magnitude of any cost overruns or underruns (Rep. 37, 123). The variable rate of return concept was discussed earlier in our comments. The Commission agrees with the President as to the value of this regulatory device and will incorporate such a provision in the final approved tariffs.

In addition, the tariffs must give effect to the President's conclusion that "[e]xtraordinary consumer guarantees prior to completion of the project are judged to be unnecessary." (Rep. 121). The President, while not specifically endorsing any tariff provisions, notes that the Alcan financial advisors and sponsors believe the system can be financed without an "all-events" tariff, making equity holders bear the risks of non-completion. (Rep. 120, 124). It is contemplated, however, that once the delivery system has commenced initial operation, consumer charges would be designed to maintain debt service in the event of some service interruptions. The President has clearly stated that the effective date of any tariff or agreement to pay a fee, surcharge, or other payment shall not be prior to the completion of construction and the initiation of service of the system. (Rep. 37). The Commission endorses this condition as necessary to protect the interests of the gas purchasers and the ultimate consumers.

Finally, the Commission recognizes that the President's Report, the Agreement on Principles, and the Applicants anticipate that the gas transportation system tariffs may employ a cost of service formula as opposed to a stated rate. The Commission notes that the accepted regulatory and industry understanding is that a cost of service rate form would be computed according to the same principles as a stated rate. These computations include consideration of operation and maintenance expenses, an allowance for depreciation and amortization, an allowance for return, income taxes, taxes other than income, and revenue credits.

The Commission recognizes that arranging firm financing for construction of the system can be based only upon FERC approved tariff provisions, but the Commission is not prepared at this time to specify in any more detail those provisions which would be acceptable in designing a tariff for the gas transmission system for the Alaskan gas. To do so now would be impractical and ill-advised without the benefit of having a filed tariff before us.

III. The United States-Canada Agreement

As described in the Report, the U.S. shippers are at a minimum required to pay at least 66-2/3% of the cost of service for the facilities in Zone 11 (Dawson to Whitehorse segment). The Report incorporates the Agreement on Principles governing the computation of the Zone 11 cost of service. It is contemplated that the costs to be recovered will be developed consistent with the tariffs for the overall project.

The Agreement also provides for the allocation of the costs of the joint use facilities, i.e., facilities used to transport Alaskan and northern Canadian gas. This cost allocation is to be based on the following principles:

1. The joint-use facilities will be broken into zones with the costs associated with each zone accounted for separately.
2. The allocation factors are to be contracted volumes adjusted to reflect the effect of commingling on the original thermal content of Alaskan gas for U.S. shippers and northern Canadian gas for Canadian shippers.

3. Line pack will be provided by each shipper based on contracted volumes transported.
4. Fuel will be allocated among shippers on the basis of the content of the gas as it affects fuel usage.

The Commission agrees that the zoning of the system with separate accounting for each zone is a reasonable and equitable method to account for the costs to be allocated. It is reasonable to use the contracted volumes, as adjusted to reflect the effect of commingling on the original thermal content of each shipper's gas, to allocate the transportation costs of the joint-use facilities and to require that each shipper provide its share of line pack and fuel consumption. The content of the gas affects fuel usage in two ways. First, as the specific gravity of the gas increases, the pressure drop between two points on a pipeline increases. This in turn increases the compressor horsepower needed to transport the gas, which increases fuel requirements. Second, the thermal content of the gas directly affects the fuel consumption. The Commission understands that both of these properties of the original gas will be taken into account in determining the amount of fuel to be supplied by a shipper.

IV. Tracking or Flow-Through of Costs

The Report appears to assume that all costs associated with the purchase and transportation of Alaskan gas to markets will be flowed through to consumers on a current basis. However, the specific provisions for accomplishing complete tracking are not described or discussed. The Judge's decision adopted the applicants' proposals for "perfect tracking", i.e., all changes in costs automatically flow through to the end-use consumer. The FPC Recommendation did not uphold the Judge on this issue. Instead, the FPC found, in the context of approving a cost of service form of a tariff, that the purchased gas costs and transportation charges would be included in the cost of service of a jurisdictional pipeline shipper as operating and maintenance expenses. In lieu of a tracking provision, the FPC found that sufficient protection could be provided by simply agreeing to suspend the portion of general rate increases filed by the shipper attributable to operation and maintenance expenses for only one day. A third alternative was supported by staff. Under this method, the guaranteed minimum bill under the tariffs would be treated as a demand cost and recovered through a shipper's demand charge. The remaining portion of the costs of purchasing and transporting Alaskan gas would be recovered through a shipper's commodity charge. Any changes in the minimum bill for the transportation system would be made in a shipper's general rate increase filing.

The Report did not select the mechanism for flow-through of costs. Therefore, FERC would make this determination based on its evaluation of such proposals as are subsequently filed with it.

V. Marketability of the Alaska Gas

A. Delivered Costs

In the expected cost overrun case, the 20 year average transportation cost of Alaskan gas 28/ in 1975 dollars amounts to $1.04 plus a possible allowance for processing. (Rep. 95). Assuming a wellhead price of $1.45, the average delivered cost ($1.04 + $1.45 + possible processing costs) is below the estimated minimum cost of LNG ($3.25) and SNG ($3.75) (Rep. 96). However, these average delivered costs are close to the estimated cost of substitute fuel oil at $2.60 (Rep. 97).

28/ The delivered cost will be higher in the initial years and lower in the later years of service.

The average transportation cost ($1.04) is not representative of the tariff that would be paid in the early years, unless the tariff were levelized in which event there would be a higher overall cost to consumers. We have examined some additional scenarios regarding the delivered cost in the early years and the possible impact on marketability. Assuming that the Alaskan gas is priced either on a rolled-in basis or pursuant to the pricing provisions of the National Energy Plan, we conclude that the gas would be marketable even in the early years without a levelized tariff. Of course, the final determination in regard to marketability will be made by the purchasers.

The following table shows the impact of the declining cost of service.

Table II

Annual Alcan Cost for Expected Cost Overrun Case

(1975 dollars)

	Transportation Cost	Delivered Cost (Wellhead price = $1.45)[29]	Delivered Cost (Wellhead price = $2.00)[29]
1984	2.00	3.45 - 3.75	4.00 - 4.30
1985	1.81	3.26 - 3.56	3.81 - 4.11
1986	1.71	3.16 - 3.46	3.71 - 4.01
1987	1.57	3.02 - 3.32	3.57 - 3.87
1988	1.43	2.88 - 3.18	3.43 - 3.73
1989	1.30	2.75 - 3.05	3.30 - 3.60
1990	1.19	2.64 - 2.94	3.19 - 3.49
1991	1.10	2.55 - 2.85	3.10 - 3.40
1992	1.02	2.47 - 2.77	3.02 - 3.32
1993	.93	2.39 - 2.69	2.94 - 3.24
1994	.87	2.32 - 2.62	2.87 - 3.17
1995	.81	2.26 - 2.56	2.81 - 3.11
1996	.76	2.21 - 2.51	2.76 - 3.06
1997	.71	2.16 - 2.46	2.71 - 3.01
1998	.67	2.12 - 2.42	2.67 - 2.97
1999	.63	2.08 - 2.38	2.63 - 2.93
2000	.59	2.04 - 2.34	2.59 - 2.89
2001	.57	2.02 - 2.32	2.57 - 2.87
2002	.53	1.98 - 2.28	2.53 - 2.83
2003	.49	1.94 - 2.24	2.49 - 2.79

[29] The variation in the delivered cost component for each year is due to the use of zero or 30¢ per Mcf as the cost of processing. (*Supra*, p. 17).

The values in the table are estimates of the cost of service at an average point of departure from the Pipeline in the Contiguous United States.30/ Additional transportation costs within the Contiguous United States and local distribution costs must be added to these figures to obtain estimates of burner-tip prices. Assuming (1) that Alaskan gas will not be transported more than 500 miles once it leaves the Pipeline and (2) a transportation cost of $.03/Mcf/100 miles, additional transportation costs within the lower 48 states will range from 0 - $.15. Average distribution costs in 1976 were approximately $.60/Mcf.31/ Thus, adding $.75 to the delivered costs in the table gives a conservative estimate of the cost of service to the burner tip. In comparison, the cost of

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30/ These costs will vary slightly depending upon where the gas exits from the Western Leg or the Northern Border system.

31/ The average price received by interstate pipeline companies in the 12 months ending in Dec. 1976 was roughly $1.00/Mcf. (FPC News Release No. 23153 May 23, 1977). The average gas utility price in 1976 was $1.60/MMBtu. (American Gas Association, Gas Facts 1976 p. 111). Average distribution cost = $1.60 - $1.00 = $.60.

residential heating oil was estimated to range from $2.88 - $.60/MMBtu (1975 dollars) based on estimates of domestic refinery acquisition costs for crude oil in 1984 of $16 - $20/bbl.[32]

32/ According to "Monthly Energy Review," Office of Energy Information and Analysis FEA, August 1977, the average price for residential heating oil during the first 5 months of 1977 was 62% more than the average refinery acquisition cost. Thus, the average price of residential heating oil in 1984 = ($16/bbl) (1.62) = $25.92/bbl. Converting to 1975 dollars at a 5% discount rate gives $16.71/bbl. Assuming 5.8 MMBtu/bbl results in a price of $2.88/MMBtu. The same sequence of calculations assuming of price of $20/bbl for crude oil in 1984 gives a price of $3.60/MMBtu.

B. Wellhead price of $1.45

If the Alaskan gas were required to be offered at its incremental cost, it might be difficult to market the gas in the early years of the project even with a wellhead price of $1.45 per Mcf. However, it is not anticipated that the gas would be marketed on an incremental basis. The Report calls for a pricing approach similar to that proposed in the National Energy Plan (Rep. 46). Under that approach low priority users would absorb the cost of higher priced supplies up to the Btu equivalent of substitute fuels (No. 2 fuel oil). Any costs not recovered in this manner would then be rolled-in to both low and high priority customers. If the Alaskan gas is offered in this manner or on a fully rolled-in basis, marketing difficulties probably will not arise.

In order to determine whether Alaskan gas can be marketed on a rolled-in basis beginning in 1984, it is necessary to estimate the composition of the gas supply and the prices of the supply components. This is a speculative venture involving assumptions about the volumes and prices of LNG, SNG, Mexican gas, new domestic supplies, and roll-over gas. Clearly, the more expensive these other sources are, the more difficult it is to roll-in the Alaskan gas and achieve a weighted average price which is competitive with substitute fuels.

An indication of whether marketability problems are likely to arise can be obtained by calculating a feasible upper limit for the price of non-Alaskan supplies. Assuming that the cost of service for the Alaskan gas is $4.50 ($3.75 + $.75) and that Alaskan gas constitutes 20% of pipeline supplies, the average cost of non-Alaskan supplies could not exceed $3.38 (1975 dollars) for the rolled-in price of all gas to be less than $3.60, the high estimate for the cost of substitute fuels. Given continued regulation, it is not likely that the average cost of non-Alaskan gas will exceed $3.38 by 1984.

C. <u>Wellhead price of $2.00</u>

Under incremental pricing and perhaps even on a rolled-in basis, marketing of this gas would be questionable. Analogous calculations to those above indicate that if the Alaskan gas constituted 20% of pipeline supplies, the average cost of non-Alaskan gas could not exceed $3.23 for the rolled-in price to remain competitive. This seems possible even assuming increased availability of high cost supplements such as LNG and SNG.

D. Royalties in-kind

One unresolved issue is whether the State of Alaska is going to take its royalties in-kind. This issue should be resolved prior to certification, because if Alaska chooses to take its royalties in kind, the system should be redesigned and the unit transportation cost probably will rise.

E. Level tariff

The Report raises the question of whether FERC should permit a leveling of the delivered rate (Rep. 159). Without prejudging this matter, we wish to point out that an attempt to levelize rates over the accounting life of the project may have serious implications with respect to the project for the following reasons:

1) It will require significant deviations from the requirements of the Uniform System of Account and generally accepted accounting principles with respect to asset valuation, revenue recognition and matching of cost;

2) Levelization of a rate will significantly reduce cash flow to the project during the earlier years of the project, thereby impairing the ability to finance by increasing risk to debt holder and delaying payment of dividends to equity holders;

3) Significant increases in total cost to the consumer over the life of the project will be experienced since carrying charges on unrecovered investments will increase significantly;

4) Depending on the extent of levelization, it could impair equity investors' ability to utilize available tax deductions at the earliest time permitted by the Tax Code, thereby increasing the cost to consumers.

Any determination to level payments will require consideration of the above factors. Also, the use of an interim rate for a limited period of time is an option that deserves consideration. It is contemplated that the use of a level rate for the entire period or the use of an interim rate will be considered by FERC in issuing a final certificate.

COMMENTS ON CHAPTER V
"Safety, Reliability, and Expansibility"

In the area of safety and geotechnical feasibility, the President's Report is consistent with the FPC Recommendation issued May 2, 1977. The Commission concurs with the findings and recommendation of the President in this chapter. The only comment which the Commission finds appropriate is that the "technical study group" envisioned in Section 10 of the Agreement on Principles should be implemented as soon as possible in order to test and evaluate the several possible pipe diameters and pressures. Expeditious resolution of pipe selection is of great importance to the Commission because final certification cannot proceed in its absence.

COMMENTS ON CHAPTER VI
"Organization of Federal Government Involvement After System Selection"

By proposing an executive reorganization under which Agency Authorized Officers of the various agencies involved with the Pipeline would be under the direction of the Federal Inspector, who in turn would be subject to the direction of the Executive Policy Board, the President would take steps to coordinate governmental oversight of construction and management of the Alcan project in order to eliminate government caused construction delays. The Commission endorses this principle of coordinating the various governmental agencies in order to reduce the number of points of contact between the government and the applicants.

It is assumed that FERC, having established terms and conditions for the certificates involved, will be accorded an Agency Authorized Officer as a part of the Alaskan Natural Gas Pipeline Office to ensure that Alcan satisfies its certificated obligations. In addition, utility regulation requires that prior to the inclusion in rate base of an expenditure by the utility, the regulatory body must pass on the prudency of its incurrence. The question then arises as to the role of FERC's Agency Authorized Officer in auditing and possibly ruling upon the prudency of the applicants' construction expenditures as incurred.

Several different methods of auditing are possible. In the Alaskan gas pipeline proceeding before the FPC, Administrative Law Judge Litt endorsed a construction phase audit scheme employing the FPC's Uniform System of Accounts, and he noted in passing that "/i/ f the Alaska Natural Gas Transportation Act of 1976 is in effect, a question is raised as to whether a joint FPC effort with the board or inspector of construction appointed pursuant to that statute would be in order." (Initial Decision, p. 405, n. 1.) Then in its recommendation to the President, the FPC made a similar finding that "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." (FPC Recommendation, p. XII-70.) If this ongoing construction phase audit and rate base approval is to be implemented, FERC would have to be in close contact with the construction effort, in the form of an Agency Authorized Officer representing FERC. If this ongoing determination of prudency of construction costs is to be absolutely final, then it is appropriate to establish some expedited FERC review process before the Agency Authorized Officer rules upon specific construction costs. On the other hand, the Agency Authorized Officer could make an independent decision which would later be treated by FERC as presumptively correct, subject to reversal only if shown to be clearly wrong.

In addition, there may be other methods of handling this problem suggested by the applicants or other interested parties during the certification procedure. A final decision on the most appropriate auditing technique requires further study and added input from the concerned entities.

COMMENTS ON CHAPTER VII
"Impact on Competition in the Natural Gas Industry"

The Report recommends at page 211 that the Commission:

> should use its approval power of gas purchase contracts, and more generally, over project financing plans, to ensure that any conditions producers impose in exchange for debt guarantees do not create situations which might permit abuse of competition.

The Commission concurs with this recommendation and intends to implement the recommendation. For purposes of illustration, the Commission sets forth the type of conditions which may be required in the certificates and gas purchase contracts to carry out this responsibility

1. Certificate to construct the transportation system

    a. An open access provision. Example - 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.

    b. The owners of the pipeline shall not attempt to restrict pipeline throughput.

2. Gas Purchase Contracts

    a. Buyer and seller affirm that they have revealed any or all collateral agreements, whether written or verbal, that relate to the purchase of this gas.

b. Buyer agrees to provide the Commission with copies of any contracts involving the resale of Alaskan gas and to inform the Commission of any collateral agreements, whether written or verbal, involving the resale of this gas. Buyer agrees that it will not attempt to impose provisions in any resale contracts that would tend to lessen competition.

c. Seller and buyer agree to inform the Commission of any conversations, negotiations or meetings held with other sellers or buyers (actual or potential) regarding gas reallocation and displacement.

This list is neither exhaustive nor final. The Commission will entertain suggestions from interested parties, especially the Department of Justice.

COMMENTS ON CHAPTER IX
"Western Leg"

The Report approves the construction of a Western Leg consisting of the facilities proposed by Pacific Gas and Electric Company and its affiliate, Pacific Gas Transmission Company, which are described as the "1580" design. These new facilities would provide for the direct delivery of Alaskan gas to the West Coast.

The President's decision was predicated on (a) an indication that there would be a short term increase in the delivery of Canadian gas and the possibility of a continuation of the existing export licenses, and (b) the probability that the projects currently proposed by El Paso Natural Gas Company will commence as scheduled, thus pre-empting the excess capacity in the southwestern systems and precluding the possibility of displacement. More specifically, the President's Report notes that delivery of Alaska gas to California by El Paso Natural Gas Company and Transwestern Pipeline Company through displacement would not be a feasible alternative to construction of the Western Leg if (a) one of El Paso's 30-inch lines is converted from a gas line to an oil line by the Sohio Project; (b) substantial volumes of Mexican gas become available for transportation to the West Coast; (c) there are any advanced or increased deliveries of Canadian gas to the U.S. which would also have to be moved West by displacement; and (d) the Algeria II LNG import project is completed on schedule. The President's Report finds that all of these events are likely to occur, and concludes that the displacement option would not be a viable alternative to construction of the Western Leg.

The Report also states that prior to FERC certification of the Western Leg, the Secretary of Energy will determine the size and volume of the Western Leg to be certified, as well as review the need for any prebuilding necessary to take gas under a predelivery arrangement (Rep. 233).

It is noted that the FPC's May 2, 1977, Recommendation did not support approval of the Western Leg at that time. However, based upon the additional information available to the President, as discussed above and in the Report, the Commission offers no objection to the President's decision on this issue.

GENERAL COMMENTS

I. Future Actions Under The Natural Gas Act

All Federal agencies retain their existing authorities pursuant to Section 9(a) of the ANGTA to issue certificates and other required permits. Thus, the President's Decision recognizes that further action under the Natural Gas Act (NGA), as well as ANGTA, will be required prior to construction and operation of the approved system. The actions should be taken in an orderly fashion to permit construction planning and preconstruction financing to begin at the earliest practicable moment, at the same time assuring that all approvals needed for ultimate operation of the system and distribution of gas are obtained. To accomplish this, conditioned certificates of public convenience and necessity should be issued promptly in accordance with the final selection, upon such terms and conditions as specified in the Decision and under any additional conditions as may be required by the public convenience and necessity under Section 7(e) of the NGA.33/ The holders of these certificates will have the power of eminent domain specified in Section 7(h) of the NGA.

33/ At a public conference held September 30, 1977, representatives of Alcan suggested that, assuming Congressional approval, they would present to the Commission for review and approval a proposed conditional certificate that listed, in sequence, all the additional procedural steps necessary.

The order issuing these certificates will begin the regulatory approvals needed for the ultimate operation of the system. In accordance with the statutory requirements of the Natural Gas Act, approvals will be needed for producers making sales of natural gas, by pipelines for displacement arrangements, for export or import authority and other actions. 34/ Compliance filings will also be required by the conditional certificate. For example, a financing plan must be submitted prior to operation of the system, but the absence of such a plan need not impede preparation of the final design of the principal facilities.

In addition, the Commission may be called upon to assist in the development of construction plans and environmental safeguards as a "concerned agency" (Rep. 34). While ordinarily the Commission does not become involved in site specific planning, its expertise will be available to the Federal Inspector as needed, most likely through the Commission's Agency Authorized Officer.

34/ Certain required actions may be under the jurisdiction of entities other than FERC in the future, or actions which are now required may no longer be so, depending on Congressional action on the National Energy Plan.

II. Waiver

The President's Report recognizes that there are two statutory provisions that involve determinations subsumed in the Decision and which will require a waiver under Section 8(g) of ANGTA. Both of these waivers relate to a proposal to serve limited quantities of Alaskan gas in the Yukon and western provinces subject to providing replacement gas downstream in Canada. This transaction will be an export requiring authorization under Section 3 of the NGA 35/ and Section 103 of the Energy Policy and Conservation Act. The Commission agrees that both of these approvals would be ministerial and unnecessary determinations in light of the President's Decision, and concurs in these waivers.

Other waivers of Section 7 of the Natural Gas Act may also be required. The Decision proposes to give the Federal Inspector field authority to overrule conditions imposed by individual Federal agencies in certificates, permits, and other licenses. In addition, the Decision would also permit the Secretary of Energy to determine the appropriate capacity of the Western Leg. Waivers may be required to the extent that either of these proposals are inconsistent with the determinations made or required to be made in accordance with Sections 7(c) and 7(e) of the NGA.

35/ Actually, all gas transiting Canada falls under Section 3 of the NGA.

III. Terms and Conditions

The Commission supports the procedures for enforcement of terms and conditions, which is item I.10 in the President's proposed terms and conditions (December 31). It should be implemented as soon as possible through appointment of a Federal Inspector and agency authorized officers to establish liaison with the successful applicant at the earliest stage in the applicant's planning process.

IV. Canadian Considerations

Canada and the United States have agreed in principle on terms for approval of the transportation project. This agreement supplements the more general hydrocarbon transit treaty initialed earlier by providing specific details on cost allocation, Yukon taxation, and nondiscriminatory treatment. In addition, supporting commitments have been included from provincial governments. The Commission agrees that the assurances provided exceeds the usual level of detail available on similar projects, and this is certainly true of any international gas project of which the Commission is aware.

The Agreement on Principles provides that the respective regulatory authorities (FERC and NEB) will consult where needed on relevant points, particularly with respect to matters concerning financing, taxation, and tariffs.

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