These effects go right to the heart of the basis on which Canadian companies are able to supply gas to the export market: the assurance of a revenue stream on which to finance the production and transport of surplus gas from the wellhead to the international border. The serious implications of this do not appear to have been addressed to date in the FERC proceedings.

Because of the potential seriousness of the matter, our National Energy Board has taken the unusual step of making a formal submission to the FERC proceeding on Order 380. I am attaching a copy of the Board's submission and hope you will examine carefully the concerns it raises. Moreover, as you know, in view of the special nature of the project, the Canadian Government has already requested consultations on the implications of Order 380 on the Prebuild, under article 8 of the Northern Gas Pipeline Agreement. These consultations are scheduled for July 3 in Washington, D.C. As well, we understand that several Canadian and U.S. companies have formally requested rehearing.

We are hopeful that Canadian concerns relating to Order 380 will be resolved through the FERC review proceedings and the Prebuild consultations. We believe that this should be possible without prejudicing the objectives of the rulemaking. At the same time, we are seeking your assurance that we will be given an opportunity for further high level discussions as necessary between our two governments before any final actions are taken on this Order, which could adversely affect our long term gas trade.

Yours sincerely,

Allan Gotlieb
Ambassador

**Foothills Pipe Lines Ltd.**

ROBERT L. PIERCE, QC
CHAIRMAN AND CHIEF EXECUTIVE OFFICER

February 10, 1992

Mr. D.W. Campbell
Commissioner, Northern Pipeline Agency
Lester B. Pearson Bldg.
125 Sussex Drive
Ottawa, Ontario K1A 0G2

Dear Mr. Campbell:

On January 14, 1992, Mr. Michael J. Bayer, the U.S. Federal Inspector for the Alaska Natural Gas Transportation System ("ANGTS") sent President Bush a report which essentially recommends that the United States abandon its support for the completion of the project. Among other things, Mr. Bayer recommends (1) the repeal of the Alaska Natural Gas Transportation Act ("ANGTA"), which limits the ability of U.S. regulatory and agencies to interfere with the construction of the ANGTS; (2) termination of long-standing agreements with Canada relating to the project; (3) withdrawal of a 1977 presidential decision approving the project; and (4) abolition of the Office of the Federal Inspector.

While Foothills does not object to the abolition of the Office of the Federal Inspector, we believe the Canadian government must strongly protest Mr. Bayer's other recommendations. In our opinion, there is no justification for the United States to repudiate its commitments to Canada on the ANGTS, or to otherwise abandon its support for this important bilateral project.

As you are aware, one of the important cornerstones of the ANGTS is the 1977 "Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline." That agreement--which is still in full force and effect--was designated to provide benefits and protections to *both* the United States and Canada, with respect to the delivery of gas from *both* Alaska and Canada's Mackenzie Delta. Significantly, the agreement commits the United States and Canada to take all measures necessary, including legislative measures, to facilitate the construction and operation of the ANGTS.

When the Canadian government approved the "prebuilding" of the existing Foothills system in 1980, in order to provide new Canadian gas exports to the United States, it required additional assurances that the United States government would remain committed to the completion of the entire project. As a result, the U.S. Congress passed a resolution on July 1, 1980, declaring, among other things, that completion of the ANGTS "enjoys the

2900, 801 SEVENTH AVENUE S.W. CALGARY, ALBERTA T2P 2N6 (403) 290-7800

highest level of Congressional support..." In addition, President Carter sent the Canadian Prime Minister a letter on July 17, 1980, stating:

> "I can assure you that the U.s. Government not only remains committed to the project; I am able to state with confidence that the U.S. Government now is satisfied that the entire Alaska Natural Gas Transportation System will be completed."

In light of these commitments, both the Canadian government and Foothills have frequently expressed their concern over the proposal of Yukon Pacific Corporation to export large volumes of North Slope gas to the Pacific Rim. In response, the United States has consistently asserted that its approval of such exports was not a retreat from the bilateral commitments on the ANGTS. For example, in his 1988 generic finding on Alaskan gas exports, President Reagan stated: "I do not believe this finding should hinder completion of the Alaska Natural Gas Transportation System ("ANGTS"). Moreover, the Department of Energy's 1989 decision authorizing gas exports by Yukon Pacific stated that "DOE does not believe approval of the proposed TAGS export to be inconsistent with the U.S. Government's commitment to ANGTS."

Similar representations have been made directly to Foothills through the years. For example, United States Trade representative Clayton Yeutter sent a letter to Foothills Chairman on July 31, 1987, stating:

> "...I am sensitive to existing commitments which could be adversely affected by a decision on ANS exports, and the Administration is pledged to meet certain commitments to the Government of Canada. *I can assure you we will meet our commitments fully.*" (emphasis added).

On the basis of the United States' commitments, which have been reaffirmed repeatedly during the past fifteen years, Foothills has invested approximately $1 billion in Phase I of the project -- *i.e.*, the "prebuild" phase, and many million additional dollars in Phase II, including AFUDC (allowance for funds used during construction).

These investments have been made with the understanding that the United States would continue to honour its commitments on the ANGTS, just as Canada has honoured its commitments. Under these circumstances, it would be patently unfair for the United States to now abandon the project, without regard to the impact on the project's sponsors.

We recognize that completion of the ANGTS has been delayed as a result of the gas surplus which has characterized North American gas markets during recent years. That is no reason, however, to destroy the important work which has been done in both countries. The foundation of the project has been laid, and it should remain intact, so that Alaskan gas can move to the lower forty-eight states when it is needed--as surely it will be.

Your assistance on this matter is appreciated. If you have any questions, do not hesitate to give me a call.

Yours sincerely,

R.L. Pierce
Chairman and
Chief Executive Officer

:js

February 7, 1992

The Honorable George Bush
The White House
Washington, D.C. 20500

Dear Mr. President:

On January 14, 1992, Mr. Michael J. Bayer, the Federal Inspector for the Alaska Natural Gas Transportation System, sent you a report containing certain recommendations with respect to ANGTS.

On behalf of Alaskan Northwest Natural Gas Transportation Company, the general partnership responsible for the Alaskan segment of the ANGTS project, we reiterate our continued support for the project. ANGTS represents the most economic and environmentally sound means of moving Alaskan North Slope gas to market, and the existing legislative and regulatory framework assures that ANGTS can be expeditiously completed when market conditions warrant.

As sponsor of the uncompleted U.S. segment of ANGTS, we urge you to continue honoring the assurances and the commitments made by the government of the United States to the Canadian government in respect to ANGTS. We believe it is important for the United States and Canada to maintain a cooperative working relationship in the energy area as well as other areas of common interest. Moreover, there is no need to burden Congress with the extensive legislative process that would result from a proposal to repeal ANGTA.

We certainly understand, however, the need for maintaining prudent and efficient budget procedures within the Executive Branch while at the same time fulfilling its oversight responsibilities under ANGTA. If the need for such efficiency suggests elimination of OFI and transfer or consolidation of oversight responsibility within an appropriate department of DOE then we encourage your consideration of appropriate legislative and executive action necessary to implement such reorganization.

We appreciate your attention to this matter and are available to discuss this matter with your staff if that is desired.

Respectfully,

Vernon T. Jones
Chairman of the Board of
Partners of Alaskan
Northwest Natural Gas
Transportation Company

cc: His Excellency
Derek H. Burney
The Ambassador of Canada

Canadian Embassy Ambassade du Canada

No. 026

The Embassy of Canada presents its compliments to the Department of State and has the honour to draw to the Department's attention certain recommendations made to the President of the United States by the Federal Inspector of the Alaska Natural Gas Transportation System in his Report on the Construction of the Alaska Gas Transportation System dated January 14, 1992.

Among the Federal Inspector's ten recommendations are six that are relevant to Canada:

- repeal the Alaska Natural Gas Transportation Act;
- eliminate the exclusive ANGTS route to transport Alaska North Slope gas to the Lower 48;
- eliminate the ANGTS project sponsors' unique legal-monopoly status;
- withdraw the President's Decision and Report, rescind Executive Order 12142 and withdraw Reorganization Plan No. 1 of 1979;
- terminate the 1977 Agreement of Principles with Canada;
- terminate the 1980 Procurement Procedures Agreement with Canada.

.../2

The Canadian Government expects that the United States will continue to honour its obligations under the 1977 Agreement of Principles and subsequent assurances given to the Government of Canada with respect to the pipeline. Any action giving effect to the above-noted recommendations would be contrary to the obligations of the United States and would not be acceptable to Canada.

The Embassy of Canada avails itself of this opportunity to renew to the Department of State the assurances of its highest consideration.

Washington, D.C.

14 February 1992

# United States Senate

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

March 12, 1992

President George Bush
Executive Office of the President
1600 Pennsylvania Ave., NW
Washington, DC 20500

Dear Mr. President:

On January 14, 1992, the Office of the Federal Inspector for the Alaska Natural Gas Transportation System (ANGTS) sent you a report which, among other things, recommends abrogation of the Alaska Natural Gas Transportation Act, the 1977 Presidential and Congressional decisions approving the ANGTS, and the U.S./Canadian agreements which underpin the project. According to an article which appeared in a recent edition of Inside F.E.R.C., the White House has decided to embrace these recommendations. More specifically, the article states that Nicholas Calio, Assistant to the President for Legislative Affairs, has sent a letter to the Chairman of the House Subcommittee on Energy and Power, stating that the "the president looks forward to working with you to repeal ANGTS authorities in a time frame consistent with the FY-93 budget."

If those press reports are correct, I strongly urge that you reconsider the actions which have been proposed by the Federal Inspector. While completion of the ANGTS has been delayed as a result of current market conditions, it is clear that the American consumers will eventually need access to Alaskan North Slope gas. It is likewise clear that the ANGTS -- which has been approved by both the United States and Canadian governments -- would be the most economic and environmentally sound means of providing that access.

Significantly, a repeal of the Alaska Natural Gas Transportation Act would expand the authority of the regulatory agencies and the courts to delay the completion of the ANGTS. Moreover, termination of the U.S.-Canadian agreements would leave the United States without any obligation by Canada to permit an overland pipeline across Canadian soil to provide access of Alaskan gas when it is needed. Termination of the U.S.-Canadian agreements would also leave U.S. consumers without agreed-upon protections on such matters as pipeline capacity, rates, tariffs, and taxes.

Finally, there is simply no reason at this point for the Administration, Congress, and the Canadian government to become involved in a debate on the future of Alaskan gas. There are more pressing problems, particularly the economy, which deserve our immediate attention.

Sincerely,

J. Bennett Johnston

Canadian Embassy          Ambassade du Canada

501 Pennsylvania Avenue, N.W.
Washington, DC

August 19, 1999

Mr. James J. Hoecker, Chairman
Federal Energy Regulatory Commission
888 First Street, NE
Room 11A-1
Washington, D.C. 20426

Dear Chairman Hoecker,

I am writing with regard to the "Order Accepting and Suspending Tariff Sheets, Subject to Refund and Hearing" on the Northern Border Pipeline Company (Docket No. RP99-322-0000), issued on June 30, 1999.

In this Order, the Commission states that the Alaska Natural Gas Transportation System (ANGTS) is "no longer viable". Given that the United States and Canada remain bound by the 1977 "Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline" and that the Commission cannot modify action which was approved by Congress, I suspect that it was not the Commission's intention to create uncertainty with regard to the ANGTS.

It would therefore be helpful if the Commission would clarify the meaning of the phrase in question so as to alleviate any concern which may have occurred among interested parties.

Best Regards. RC

Yours sincerely,

Raymond Chrétien

Raymond Chrétien

cc: All FERC Commissioners

**1012**

DOE002-1022

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
Vicky A. Bailey, William L. Massey,
Linda Breathitt, and Curt Hébert, Jr.

Northern Border Pipeline Company ) Docket Nos. RP99-322-001
) RP96-45-000

ORDER ON CLARIFICATION AND REHEARING
AND CONSOLIDATING PROCEEDINGS

(Issued August 31, 1999)

Northern Border Pipeline Company (Northern Border) filed tariff sheets proposing to increase its rates by $30 million and to make other changes. In an order issued June 30, 1999, the Commission accepted and suspended the tariff sheets for the maximum five-month period, to be effective December 1, 1999, subject to refund, conditions, and the outcome of a hearing.[1] Foothills Pipe Lines Ltd. (Foothills); Husky Gas Marketing Inc., ProGas U.S.A., Inc., and Renaissance Energy (U.S.) Inc. (collectively, Husky); Pan-Alberta Gas Ltd. and Pan-Alberta Gas (U.S.) Inc. (Pan-Alberta/PAGUS); Amerada Hess Corporation (Amerada Hess); and Northern Border ask for clarification or rehearing of various aspects of the June 30 order.

Northern Border was originally planned as part of the Alaskan Natural Gas Transportation System (ANGTS), which would transport gas from Alaska through Canada and into the lower 48 states of the U.S.[2] Northern Border was to be the eastern leg of the lower-48 state portion of the system, serving Midwest markets. In the early 1980s, the Canadian and lower-48 state portions of the system were built before the Alaskan portion, which has still not been constructed. Northern Border has subsequently expanded its system several times.

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[1] 87 FERC ¶ 61,380 (1999).

[2] Alaska Natural Gas Transportation Act of 1976, 15 U.S.C. 719 et seq.; Presidential Decision Designating Transportation System (September 22. 1977), approved by Public Law 95-158 (November 9, 1977; 91 Stat. 1268).

Discussion

For the reasons discussed below, the Commission grants in part and denies in part the requests for clarification or rehearing.

A. Cost-of-service tariff

Foothills, whose subsidiaries are responsible for owning, constructing, and operating the 2,000 mile Canadian segment of the ANGTS, filed a request for clarification, or in the alternative, rehearing of a statement concerning ANGTS that the Commission made in the context of its discussion of Northern Border's tariff.

Norther Border has what is known as a cost-of-service tariff. Its rates are not based on fully allocated costs or projected units of service during a test period, but rather on the pipeline's incurred costs which are allocated to its firm services with adjustments every six months.[3] As Northern Border explained, its cost-of-service tariff permits recovery of its cost of service on an actual monthly basis as opposed to designing rates on the basis of an historical, illustrative test year.[4]

In their protests to Northern Border's filing, Husky and Pan-Alberta/PAGUS objected to Northern Border's continued use of a cost-of-service tariff, and requested the Commission set that issue for hearing. The June 30 order included the issue of Northern Border's continued use of its cost-of-service tariff in the hearing established on Northern Border's filing. The Commission observed that the original pipeline was 822 miles and commenced service in September, 1982, while currently, Northern Border's pipeline

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[3] 76 FERC ¶ 61,141 at 61,766 (1996). Revenues from interruptible transportation are credited prior to the allocation of incurred costs to firm service.

[4] Letter of Transmittal at 1, Docket No. RP99-322-000 (May 28, 1999). Thus, in Order No. 582, the Commission stated that "[b]ecause of the nature of cost-of-service tariffs, Northern Border would only file under section 154.314 when changes in an approved rate of return or services are proposed." Therefore, instead of the schedules required by section 154.312, Northern Border filed Statements L, M, O, and P, and other information under section 154.314 required to support its filing. At Northern Border's request, the Commission waived the filing requirements in waiver of sections 154.301(a), which concerns the filing of statements and schedules described in sections 154.312; 154.303, which requires statements filed pursuant to section 154.312 to be based on a test period; section 154.311, which requires the updating of certain filed statements; and sections 154.312(a) through (q), which concern the composition of required statements.

extends a total of 1,215 miles and Northern Border has plans for further expansion. The Commission concluded there should be an investigation into the continued viability of Northern Border's cost-of-service tariff under section 5 of the NGA "because the ANGTS is no longer viable and Northern Border has expanded beyond its original pipeline area." [5] In accordance with these findings, the Commission set the matter for hearing.

Foothills does not object to the Commission's decision to set the issue of whether Northern Border should retain a cost-of-service tariff for hearing. However, it asks the Commission to clarify its statement that ANGTS is no longer viable. Foothills asserts the Canadian segment was built in reliance on commitments and assurances given the Canadian government by the United States President and Congress and by the Commission regarding the ANGTS project. [6] Foothills asserts there is no factual evidence for the Commission's statement concerning viability and that the Commission has previously set this issue for hearing without making such a finding. [7]

The Commission grants the motion for clarification. The Commission's intent was to indicate that the immediate conditions surrounding Northern Border's cost-of-service tariff warrant review of that tariff. The Commission did not intend to indicate that the ANGTS project would not be fully implemented or that the Commission would not honor its commitments to that project. The only matter at issue here is Northern Border's rates. The Commission intended to find only that under current circumstances there should be an investigation as to whether Northern Border's current cost-of-service tariff is just and reasonable, and if not, what the just and reasonable tariff should be. The Commission is thus setting the cost-of-service tariff for hearing since the cost-of-service tariff is of primary importance to the determination of Northern Border's rates. Further, Foothills does not object to setting the issue for hearing. Also, circumstances on Northern Border such as its physcial configuration have changed over the years, and the intervenors have specifically protested this cost collection mechanism. Further, Foothills does not object to setting the issue for hearing. The intervenors may explore the justness and reasonableness of the cost-of-service tariff through discovery and at hearing.

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[5] 87 FERC at 62,412.

[6] Agreement on Principles Applicable to a Northern Natural Gas Pipeline (September 20, 1977) (included in Presidential Decision Designating Transportation System).

[7] 73 FERC ¶ 61,399 (1995), reh'g denied, 74 FERC § 61,214 (1996).

B. The Chicago Project costs

In this rate case, Northern Border has rolled costs of its expansion facilities known as the Chicago Project into its system rates. The Chicago Project consists of facility improvements to expand the capacity of the pipeline's mainline and to extend its existing terminus by 243 miles from Harper, Iowa, to a new terminus south of Chicago, Illinois. The Commission approved the facilities and certificated them on August 1, 1997.[8] The Commission analyzed the rate impact of rolling in the costs of the expansion facilities and found that it was nine percent. Since the rate impact was greater than five percent, the Commission stated that Northern Border was not entitled to a presumption of rolled-in rate treatment. However, on analyzing the benefits to system operations in relation to the nine percent rate impact, the Commission found that Northern Border should be permitted to roll the expansion costs into its existing rates.[9]

On August 1, 1997, the same day it issued the certificate for the Chicago Project, the Commission approved a settlement between Northern Border and its customers in Docket No. RP96-45-000, Northern Border's last general section 4 rate proceeding before this one.[10] The settlement included provisions governing the Chicago Project costs. It contained a "Project Cost Containment Mechanism" (PCCM) which established a "Target Cost" for the Chicago Project of $796.8 million[11] and provided for the treatment of cost overruns and cost savings. The PCCM capped overruns by providing that Northern Border could include the first $6 million of overruns in its rates; could recover 50 percent of the overruns between $6 million and five percent of the Target Cost, and was precluded from recovering overrun costs over five percent of the Target Cost.[12]

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[8] Preliminary Determination, 76 FERC ¶ 61,141 (1996); Order Issuing Certificate, 80 FERC ¶ 61,152 (1997).

[9] 80 FERC at 61,631-32 applying "Pricing Policy Statement for New and Existing Facilities Constructed by Interstate Natural Gas Pipelines (Pricing Policy)," 71 FERC ¶ 61,241 (1995), order denying reh'g, 75 FERC ¶ 61,105 (1996).

[10] Order Approving Settlement as Modified, 80 FERC ¶ 61,150 (1997).

[11] This figure included adjustments for inflation and scope changes, $50 million for contingencies, and $75 million for project management costs. The estimated cost of the project in the certificate order issued August 1, 1997, was $792.6 million. 80 FERC at 61,625.

[12] 80 FERC at 61,610.

In the settlement order, the Commission also required Northern Border to file revised cost estimates to be used as the Target Cost for the PCCM within 30 days after final certification of the project in order to reflect the final design changes and the routing approved in the certificate, as well as the inflation factor to be used. [13] The Commission gave the parties the opportunity to comment on the revised costs. The Commission stated that the final PCCM would be based on the revised cost projections approved by the Commission. On September 2, 1997, Northern Border filed a revised Target Cost of $839,579,123 [14] which the Commission accepted by Letter Order on April 6, 1998. The settlement also required Northern Border to file a final report on its costs of constructing the Chicago Project, to be served on all the parties in the settlement docket, after the expansion is completed.

The Chicago Project apparently was put in service in December, 1998. On December 22, 1998, Northern Border preliminarily advised the Commission that no adjustment to its rate base was warranted due to the PCCM. Intervenors in this proceeding state that on June 22, 1999, Northern Border made its final report describing the cost of the Chicago Project.

Several of the parties protesting or commenting on Northern Border's rate filing in this proceeding requested that issues concerning the application of the PCCM be addressed and resolved in this proceeding, rather than the settlement docket. However, the June 30 order concluded that, since the settlement provided for the final PCCM cost report to be filed in the settlement proceeding in Docket No. RP96-45-000, all issues pertaining to the PCCM should be pursued in that docket when the final report was filed.

On rehearing, Husky and Pan-Alberta/PAGUS ask the Commission to clarify or grant rehearing that the propriety of rolling in the Chicago costs is an issue in the hearing in this case despite the Commission's statement in the June 30 order that all issues pertaining to the PCCM mechanism to control those costs should be pursued in the settlement proceeding. Amerada Hess asks the Commission to consolidate Docket No. RP96-45-000 with this docket.

While the Commission approved rolling in the costs of the Chicago Project in the Order Issuing Certificate, the Commission also recognized in that order that circumstances could change when the Chicago Project was completed and put in service. Thus, the Commission expressly recognized that parties could challenge the rolled-in pricing in

[13] 80 FERC at 61,614-15.

[14] Docket No. RP96-45-005.

Northern Border's next rate proceeding (i.e., this one) if there were changes in circumstances such as cost overruns resulting in a rate increase greater than the pipeline's projected rate increase, failure to realize claimed operational benefits, or inclusion of overrun costs in excess of the estimated costs in Northern Border's amended application. [15] Consequently, the issue of rolled-in rate treatment may be examined in the hearing in this docket.

The Commission also grants Amerada Hess's request that the settlement docket, Docket No. RP96-45-000, be consolidated with this docket. The Chicago costs or a portion of them are included in this rate filing. The amount of these costs that can be included in the rates in this filing is governed by the settlement in Docket No. RP96-45-000. That issue is also relevant to resolution of the issue whether rolled-in rate treatment of the Chicago Project is appropriate. Consequently, the resolution of the amount of Chicago Project costs to be included in the rates in this filing, as well as whether the roll-in of those costs is still appropriate, would be facilitated if the two dockets are considered together. For this reason, the Commission finds Docket Nos. RP96-45-000 and RP99-322-000 should be consolidated. The Commission also requires Northern Border to file a copy of the document referred to above that is dated June 22, 1999 and shows the total costs of the Chicago Project and other matters with the Commission within ten days of the issuance of this order. The presiding ALJ in this proceeding is to determine whether this document is the final report under the settlement and, if it is not, to set a date for the filing of the final report. The ALJ in this proceeding is to conduct any further proceedings appropriate to the PCCM and the settlement in Docket No. RP96-45-000.

D. Depreciation

Northern Border asks the Commission to clarify its statement in the June 30 order that there is not enough information concerning its depreciation rates and it should consider filing supplemental direct testimony to support those rates. It asserts it has made no change to its depreciation rates so that the burden of proof is on an opposing party to show that the existing depreciation rates are unjust and unreasonable.

Northern Border's depreciation rates were established in the settlement in Docket No. RP96-45-000, and there is no explanation in this docket as to how they were derived. The Commission recently considered a similar case in Northwest Pipeline Corp., 87 FERC ¶ 61,266 (1999). There the Commission held that the burden of proving that unchanged

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[15] 80 FERC at 61,633. The Commission also noted that under the settlement in Docket No. RP96-45-000, Northern Border agreed to absorb a portion of cost overruns pursuant to the PCCM. 80 FERC at 61,633 n.41.

depreciation rates are just and reasonable is on the pipeline, where the pipeline proposes an overall rate increase. . Here, as there, the pipeline had filed under Section 4 of the NGA to increase its rates. The Commission found the pipeline's burden of supporting its proposed rate increase includes the burden of supporting the dollar amount of each item in the cost of service since each item in the pipeline's proposed cost of service is a part of the pipeline's proposed rate increase.[16] The Commission stated this includes unchanged cost of service items, citing National Fuel Gas Supply Corp, 51 FERC ¶ 61,122 at 61,334 (1990), and Algonquin Gas Transmission Co., 64 FERC ¶ 61,293 at 63,029 n.16 (1993).

The Commission noted in Northwest that it has specifically held that it has authority to act under Section 4 of the NGA to reduce a depreciation rate and order refunds, even where the pipeline has not proposed a change in its depreciation rate, as long as the as-filed depreciation rate is a part of a proposed overall rate increase. Tennessee Gas Pipeline Co., 25 FERC ¶ 61,020 at 61,108 (1983), reh'g denied on this issue, 26 FERC ¶ 61,109 at 61,263-64 (1984). The Commission observed that it had distinguished a prior decision of the U.S. Court of Appeals for the District of Columbia Circuit holding that the Commission must proceed under NGA Section 5 to change existing cost allocation methods.[17] The Commission found the Court did not preclude a review under Section 4 of cost of service components integral to an overall rate increase.

The Commission also held in Northwest that its holding is consistent with the Court's statement in Western Resources, Inc. v FERC, 9 F.3d 1568, 1579 (D.C. Cir. 1993), that "[w]e appreciate that minor deviations from the pipeline's proposed rate based, for example, upon differences as to the extent of specific cost items, may be handled in a Section 4 proceeding." The Commission found there that the change in depreciation rate proposed by the opponents in Northwest had a relatively minor effect on the pipeline's overall cost of service, and so might the Commission find here.

Since the burden of proving that its depreciation rates are just and reasonable is on Northern Border, the pipeline must file direct testimony under 18 C.F.R. § 154.301(c) as part of its case-in-chief if it intends to sustain that burden.

[16]See also 18 C.F.R. 154.301(c) (1999).

[17]Public Service Commission of New York v. FERC, 642 F.2d 1335 (D.C. Cir. 1980), cert. denied, 454 U.S. 879 (1981).

The Commission orders:

(A) The requests for clarification and rehearing are granted or denied as discussed in the body of this order.

(B) Docket No. RP96-45-000 is consolidated with this docket and the presiding ALJ in this docket is to take all appropriate actions with respect to Docket No. RP96-45-000 as discussed in the body of this order.

(C) Northern Border is required to file a copy of the document dated June 22, 1999 describing the total costs of the Chicago Project and other matters within ten days of this order.

By the Commission.

( S E A L )

David P. Boergers

David P. Boergers,
Secretary.

233

# ALASKA NATURAL GAS TRANSPORTATION ACT OF 1976

# ALASKA NATURAL GAS TRANSPORTATION ACT OF 1976 [1]

PUBLIC LAW 94–586, AS AMENDED

AN ACT To expedite a decision on the delivery of Alaska natural gas to United States markets, and for other purposes.

*Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,*

## SHORT TITLE

SECTION 1. This Act may be cited as the "Alaska Natural Gas Transportation Act of 1976".

[15 U.S.C. 719 note]

## CONGRESSIONAL FINDINGS

SEC. 2. The Congress finds and declares that—

(1) a natural gas supply shortage exists in the contiguous States of the United States;

(2) large reserves of natural gas in the State of Alaska could help significantly to alleviate this supply shortage;

(3) the expeditious construction of a viable natural gas transportation system for delivery of Alaska natural gas to United States markets is in the national interest; and

(4) the determinations whether to authorize a transportation system for delivery of Alaska natural gas to the contiguous States and, if so, which system to select, involve questions of the utmost importance respecting national energy policy, international relations, national security, and economic and environmental impact, and therefore should appropriately be addressed by the Congress and the President in addition to those Federal officers and agencies assigned functions under law pertaining to the selection, construction, and initial operation of such a system.

[15 U.S.C. 719]

## STATEMENT OF PURPOSE

SEC. 3. The purpose of this Act is to provide the means for making a sound decision as to the selection of a transportation sys-

[1] *Presidential Decision Designating Transportation System.*—On September 22, 1977, the President submitted a decision and report to the Congress designating the Alaska Highway Pipeline route for the Alaska natural gas pipeline system. The President's decision was approved by Public Law 95–158 (Nov. 8, 1977; 91 Stat. 1268), adopted under section 8 of the Alaska Natural Gas Transportation Act of 1976. For the text of the President's decision and report, see the next items in this volume.

*Waivers of Law.*—The President submitted to the Congress findings and proposed waivers of law on October 15, 1981. The President's proposed waiver was approved by Public Law 97–93 (Dec. 15, 1981; 95 Stat. 1204) pursuant to the procedures of section 8 of the Alaska Natural Gas Transportation Act of 1976. For the text of the President's decision and report, see the next items in this volume.

tem for delivery of Alaska natural gas to the contiguous States for construction and initial operation by providing for the participation of the President and the Congress in the selection process, and, if such a system is approved under this Act, to expedite its construction and initial operation by (1) limiting the jurisdiction of the courts to review the actions of Federal officers or agencies taken pursuant to the direction and authority of this Act, and (2) permitting the limitation of administrative procedures and effecting the limitation of judicial procedures related to such actions. To accomplish this purpose it is the intent of the Congress to exercise its constitutional powers to the fullest extent in the authorizations and directions herein made, and particularly with respect to the limitation of judicial review of actions of Federal officers or agencies taken pursuant thereto.

[15 U.S.C. 719a]

DEFINITIONS

SEC. 4. As used in this Act:

(1) the term "Alaska natural gas" means natural gas derived from the area of the State of Alaska generally known as the North Slope of Alaska, including the Continental Shelf thereof;

(2) the term "Commission" means the Federal Power Commission;

(3) the term "Secretary" means the Secretary of the Interior;

(4) the term "provision of law" means any provision of a Federal statute or rule, regulation, or order issued thereunder; and

(5) the term "approved transportation system" means the system for the transportation of Alaska natural gas designated by the President pursuant to section 7(a) or 8(b) and approved by joint resolution of the Congress pursuant to section 8.

[15 U.S.C. 719b]

FEDERAL POWER COMMISSION REVIEWS AND REPORTS

SEC. 5. (a)(1) Nothwithstanding any provision of the Natural Gas Act or any other provision of law, the Commission shall suspend all proceedings pending before the Commission on the date of enactment of this Act relating to a system for the transportation of Alaska natural gas as soon as the Commission determines to be practicable after such date, and the Commission may refuse to act on any application, amendment thereto, or other requests for action under the Natural Gas Act relating to a system for the transportation of Alaska natural gas until such time as (A) a decision of the President designating such a system for approval takes effect pursuant to section 8, (B) no such decision takes effect pursuant to section 8, or (C) the President decides not to designate such a system for approval under section 8 and so advises the Congress pursuant to section 7.

(2) In the event a decision of the President designating such a system takes effect pursuant to this Act, the Commission shall forthwith vacate proceedings suspended under paragraph (1) and,

pursuant to section 9 and in accordance with the President's decision, issue a certificate of public convenience and necessity respecting such system.

(3) In the event such a decision of the President does not take effect pursuant to this Act or the President decides not to designate such a system and so advises the Congress pursuant to section 7, the suspension provided for in paragraph (1) of this subsection shall be removed.

(b)(1) The Commission shall review all applications for the issuance of a certificate of public convenience and necessity relating to the transportation of Alaska natural gas pending on the date of enactment of this Act, and any amendments thereto which are timely made, and after consideration of any alternative transportation system which the Commission determines to be reasonable, submit to the President not later than May 1, 1977, a recommendation concerning the selection of such a transportation system. Such recommendation may be in the form of a proposed certificate of public convenience and necessity, or in such other form as the Commission determines to be appropriate, or may recommend that no decision respecting the selection of such a transportation system be made at this time or pursuant to this Act. Any recommendation that the President approve a particular transportation system shall (A) include a description of the nature and route of the system, (B) designate a person to construct and operate the system, which person shall be the applicant, if any, which filed for a certificate of public convenience and necessity to construct and operate such system, (C) if such recommendation is for an all-land pipeline transportation system, or a transportation system involving water transportation, include provision for new facilities to the extent necessary to assure direct pipeline delivery of Alaska natural gas contemporaneously to points both east and west of the Rocky Mountains in the lower continental United States.

(2) The Commission may, by rule, provide for the presentation of data, views, and arguments before the Commission or a delegate of the Commission pursuant to such procedures as the Commission determines to be appropriate to carry out its responsibilities under paragraph (1) of this subsection. Such a rule shall, to the extent determined by the Commission, apply, notwithstanding any provision of law that would otherwise have applied to the presentation of data, views, and arguments.

(3) The Commission may request such information and assistance from any Federal agency as the Commission determines to be necessary or appropriate to carry out its responsibilities under this Act. Any Federal agency requested to submit information or provide assistance shall submit such information to the Commission at the earliest practicable time after receipt of a Commission request.

(c) The Commission shall accompany any recommendation under subsection (b)(1) with a report, which shall be available to the public, explaining the basis for such recommendation and including for each transportation system reviewed or considered a discussion of the following:

(1) for each year of the 20-year period which begins with the first year following the date of enactment of this Act, the estimated—

(A) volumes of Alaska natural gas which would be available to each region of the United States directly, or indirectly by displacement or otherwise, and

(B) transportation costs and delivered prices of any such volumes of gas by region;

(2) the effects of each of the factors described in subparagraphs (A) and (B) of paragraph (1) on the projected natural gas supply and demand for each region of the United States and on the projected supplies of alternative fuels available by region to offset shortages of natural gas occurring in such region for each such year;

(3) the impact upon competition;

(4) the extent to which the system provides a means for the transportation to United States markets of natural resources or other commodities from sources in addition to the Prudhoe Bay Reserve;

(5) environmental impacts;

(6) safety and efficiency in design and operation and potential for interruption in deliveries of Alaska natural gas;

(7) construction schedules and possibilities for delay in such schedules or for delay occurring as a result of other factors;

(8) feasibility of financing;

(9) extent of reserves, both proven and probable and their deliverability by year for each year of the 20-year period which begins with the first year following the date of enactment of this Act;

(10) the estimate of the total delivered cost to users of the natural gas to be transported by the system by year for each year of the 20-year period which begins with the first year following the date of enactment of this Act;

(11) capability and cost of expanding the system to transport additional the risk of cost overruns; and

(12) an estimate of the capital and operating costs, including an analysis of the reliability of such estimates and the risk of cost overruns; and

(13) such other factors as the Commission determines to be appropriate.

(d) The recommendation by the Commission pursuant to this section shall not be based upon the fact that the Government of Canada or agencies thereof have not, by then rendered a decision as to authorization of a pipeline system to transport Alaska natural gas through Canada.

(e) If the Commission recommends the approval of a particular transportation system, it shall submit to the President with such recommendation (1) an identification of those facilities and operations which are proposed to be encompassed within the term "construction and initial operation" in order to define the scope of directions contained in section 9 of this Act and (2) the terms and conditions permitted under the Natural Gas Act, which the Commission determines to be appropriate for inclusion in a certificate of public convenience and necessity to be issued respecting such system. The commission shall submit to the President contemporaneously with its report an environmental impact statement prepared respecting the recommended system, if any, and each environmental impact statement which may have been prepared respecting any other system reported on under this section.

[15 U.S.C. 719c]

OTHER REPORTS

SEC. 6. (a) Not later than July 1, 1977, any Federal officer or agency may submit written comments to the President with respect to the recommendation and report of the Commission and alternative methods for transportation of Alaska natural gas for delivery to the contiguous States. Such comments shall be made available to the public by the President when submitted to him, unless expressly exempted from this requirement in whole or in part by the President, under section 552(b)(1) of title 5, United States Code. Any such written comment shall include information within the competence of such Federal officer or agency with respect to—

(1) environmental considerations, including air and water quality and noise impacts;

(2) the safety of the transportation systems;

(3) international relations, including the status and time schedule for any necessary Canadian approvals and plans;

(4) national security, particularly security of supply;

(5) sources of financing for capital costs;

(6) the impact upon competition;

(7) impact on the national economy, including regional natural gas requirements; and

(8) relationship of the proposed transportation system to other aspects of national energy policy.

(b) Not later than July 1, 1977, the Governor of any State, any municipality, State utility commission, and any other interested person may submit to the President such written comments with respect to the recommendation and report of the Commission and alternative systems for delivering Alaska natural gas to the contiguous States as they determine to be appropriate.

(c) Not later than July 1, 1977, each Federal officer or agency shall report to the President with respect to actions to be taken by such officer or agency under section 9(a) relative to each transportation system reported on by the Commission under section 5(c) and shall include such officer's or agency's recommendations with respect to any provision of law to be waived pursuant to section 8(g) in conjuction with any decision of the President which designates a system for approval.

(d) Following receipt by the President of the Commission's recommendations, the Council on Environmental Quality shall afford interested persons an opportunity to present oral and written data, views, and arguments respecting the environmental impact statements submitted by the Commission under section 5(e). Not later than July 1, 1977, the Council on Environmental Quality shall submit to the President a report, which shall be contemporaneously made available by the Council to the public, summarizing any data, views, and arguments received and setting forth the Council's views concerning the legal and factual sufficiency of each such environmental impact statement and other matters related to environmental impact as the Council considers to be relevant.

[15 U.S.C. 719d]

PRESIDENTIAL DECISION AND REPORT

SEC. 7. (a)(1) As soon as practicable after July 1, 1977, but not later than September 1, 1977, the President shall issue a decision as to whether a transportation system for delivery of Alaska natural gas should be approved under this Act. If he determines such a system should be so approved, his decision shall designate such a system for approval pursuant to section 8 and shall be consistent with section 5(b)(1)(C) to assure delivery of Alaska natural gas to points both east and west of the Rocky Mountains in the continental United States. The President in making his decision shall take into consideration the Commission's recommendation pursuant to section 5, the report under section 5(c), and any comments submitted under section 6; and his decision to designate a system for approval shall be based on his determination as to which system, if any, best serves the national interest.

(2) The President, for a period of up to 90 additional calendar days after September 1, 1977, may delay the issuance of his decision and transmittal thereof to the House of Representatives and the Senate, if he determines (A) that there exists no environmental impact statement prepared relative to a system he wishes to consider or that any prepared environmental impact statement relative to a system he wishes to consider is legally or factually insufficient, or (B) that the additional time is otherwise necessary to enable him to make a sound decision on an Alaska natural gas transportation system. The President shall promptly, but in no case any later that September 1, 1977, notify the House of Representatives and the Senate if he so delays his decision and submit a full explanation of the basis of any such delay.

(3) If, on or before May 1, 1977, the President determines to delay issuance and transmittal of his decision to the House of Representatives and the Senate pursuant to paragraph (2) of this subsection, he may authorize a delay of not more than 90 days in the date of taking of any action specified in sections 5 and 6. The President shall promptly notify the House of Representatives and the Senate of any such authorization of delay and submit a full explanation of the basis of any such authorization.

(4) If the President determines to designate for approval a transportation system for delivery of Alaska natural gas to the contiguous States, he shall in such decision—

(A) describe the nature and route of the system designated for approval;

(B) designate a person to construct and operate such a system, which person shall be the applicant, if any, which filed for a certificate of public convenience and necessity to construct and operate such system;

(C) identify those facilities, the construction of which, and those operations, the conduct of which, shall be encompassed within the term "construction and initial operation" for purposes of defining the scope of the directions contained in section 9 of this Act, taking into consideration any recommendation of the Commission with respect thereto; and

(D) identify those provisions of law, relating to any determination of a Federal officer or agency as to whether a certificate, permit, right-of-way, lease, or other authorization shall be issued or be granted, which provisions the President finds (i) involve determinations which are subsumed in his decision and (ii) require waiver pursuant to section 8(g) in order to permit the expeditious construction and initial operation of the transportation system.

(6)[1] If the President determines to designate for approval a transportation system for delivery of Alaska natural gas to the contiguous States, he may identify in such decision such terms and conditions permissible under existing law as he determines appropriate for inclusion with respect to any issuance or authorization directed to be made pursuant to section 9.

(b) The decision of the President made pursuant to subsection (a) of this section shall be transmitted to both Houses of Congress and shall be considered received by such Houses for the purposes of this section on the first day on which both are in session occurring after such decision is transmitted. Such decision shall be accompanied by a report explaining in detail the basis for his decision with specific reference to the factors set forth in sections 5(c) and 6(a), and the reasons for any revision, modification of, or substitution for, the Commission recommendation.

(c) The report of the President pursuant to subsection (b) of this section shall contain a financial analysis for the transportation system designated for approval. Unless the President finds and states in his report submitted pursuant to this section that he reasonably anticipates that the system designated by him can be privately financed, constructed, and operated, his report shall also be accompanied by his recommendation concerning the use of existing Federal financing authority or the need for new Federal financing authority.

(d) In making his decision under subsection (a) the President shall inform himself, through appropriate consultation, of the views and objectives of the States, the Government of Canada, and other governments with respect to those aspects of such a decision that may involve intergovernmental and international cooperation among the Government of the United States, the States, the Government of Canada, and any other government.

(e) If the President determines to designate a transportation system for approval, the decision of the President shall take effect as provided in section 8, except that the approval of a decision of the President shall not be construed as amending or otherwise affecting the laws of the United States so as to grant any new financing authority as may have been identified by the President pursuant to subsection (c).

[15 U.S.C. 719e]

[1] Paragraph (6) has been repealed.

CONGRESSIONAL REVIEW

SEC. 8. (a) Any decision under section 7(a) or 8(b) designating for approval a transportation system for the delivery of Alaska natural gas shall take effect upon enactment of a joint resolution within the first period of 60 calendar days of continuous session of Congress beginning on the date after the date of receipt by the Senate and House of Representatives of a decision transmitted pursuant to section 7(b) or subsection (b) of this section.

(b) If the Congress does not enact such a joint resolution within such 60-day period, the President, not later than the end of the 30th day following the expiration of the 60-day period, may propose a new decision and shall provide a detailed statement concerning the reasons for such proposal. The new decision shall be submitted in accordance with section 7(a) and transmitted to the House of Representatives and the Senate on the same day while both are in session and shall take effect pursuant to subsection (a) of this section. In the event that a resolution respecting the President's decision was defeated by vote of either House, no new decision may be transmitted pursuant to this subsection unless such decision differs in a material respect from the previous decision.

(c) For purposes of this section—

(1) continuity of session of Congress is broken only by an adjournment sine die; and

(2) the days on which either House is not in session because of and adjournment of more than 3 days to a day certain are excluded in the computation of the 60-day calendar period.

(d)(1) This subsection is enacted by Congress—

(A) as an exercise of the rulemaking power of each House of Congress, respectively, and as such it is deemed a part of the rules of each House, respectively, but applicable only with respect to the procedure to be followed in that House in the case of resolutions described by paragraph (2) of this subsection; and it supersedes other rules only to the extent that it is inconsistent therewith; and

(B) with full recognition of the constitutional right of either House to change the rules (so far as those rules relate to the procedure of that House) at any time, in the same manner and to the same extent as in the case of any other rule of such House.

(2) For purposes of this Act, the term "resolution" means (A) a joint resolution, the resolving clause of which is as follows: "That the House of Representatives and Senate approve the Presidential decision on an Alaska natural gas transportation system submitted to the Congress on ———, 19 , and find that any environmental impact statements prepared relative to such system and submitted with the President's decision are in compliance with the Natural Environmental Policy Act of 1969."; the blank space therein shall be filled with the date on which the President submits his decision to the House of Representatives and the Senate; or (B) a joint resolution described in subsection (g).

(3) A resolution once introduced with respect to a Presidential decision on an Alaska natural gas transportation system shall be referred to one or more committees (and all resolutions with re-

spect to the same Presidential decision on an Alaska natural gas transportation system shall be referred to the same committee or committees) by the President of the Senate or the Speaker of the House of Representatives, as the case may be.

(4)(A) If any committee to which a resolution with respect to a Presidential decision on an Alaska natural gas transportation system has been referred has not reported it at the end of 30 calendar days after its referral, it shall be in order to move either to discharge such committee from further consideration of such resolution or to discharge such committee from consideration of any other resolution with respect to such Presidential decision on an Alaska natural gas transportation system which has been referred to such committee.

(B) A motion to discharge may be made only by an individual favoring the resolution, shall be highly privileged (except that it may not be made after the committee has reported a resolution with respect to the same Presidential decision on an Alaska natural gas transportation system), and debate thereon shall be limited to not more than 1 hour, to be divided equally between those favoring and those opposing the resolution. An amendment to the motion shall not be in order, and it shall not be in order to move to reconsider the vote by which the motion was agreed to or disagreed to.

(C) If the motion to discharge is agreed to or disagreed to, the motion may not be made with respect to any other resolution with respect to the same Presidential decision on an Alaska natural gas transportation system.

(5)(A) When any committee has reported, or has been discharged from further consideration of, a resolution, but in no case earlier than 30 days after the date of receipt of the President's decision to the Congress, it shall be at any time thereafter in order (even though a previous motion to the same effect has been disagreed to) to move to proceed to the consideration of the resolution. The motion shall be highly privileged and shall not be debatable. An amendment to the motion shall not be in order, and it shall not be in order to move to reconsider the vote by which the motion was agreed to or disagreed to.

(B) Debate on the resolution described in subsection (d)(2)(A) shall be limited to not more than 10 hours and on any resolution described in subsection (g) to one hour. This time shall be divided equally between those favoring and those opposing such resolution. A motion further to limit debate shall not be debatable. An amendment to, or motion to recommit the resolution shall not be in order, and it shall not be in order to move to reconsider the vote by which such resolution was agreed to or disagreed to or, thereafter within such 60-day period, to consider any other resolution respecting the same Presidential decision.

(6)(A) Motions to postpone, made with respect to the discharge from committee, or the consideration of a resolution and motions to proceed to the consideration of other business, shall be decided without debate.

(B) Appeals from the decision of the Chair relating to the application of the rules of the Senate or the House of Representatives, as the case may be, to the procedures relating to a resolution shall be decided without debate.

(e) The President shall find that any required environmental impact statement relative to the Alaska natural gas transportation system designated for approval by the President has been prepared and that such statement is in compliance with the National Environmental Policy Act of 1969. Such finding shall be set forth in the report of the President submitted under section 7. The President may supplement or modify the environmental impact statements prepared by the Commission or other Federal officers or agencies. Any such environmental impact statement shall be submitted contemporaneously with the transmittal to the Senate and House of Representatives of the President's decision pursuant to section 7(b) or subsection (b) of this section.

(f) Within 20 days of the transmittal of the President's decision to the Congress under section 7(b) 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, and (2) the Council on Environmental Quality shall provide an opportunity to any interested person to present oral and written data, views, and arguments on any environmental impact statement submitted by the President relative to any system designated by him for approval which is different from any system reported on by the Commission under section 5(c), and shall submit to the Congress a report summarizing any such views received. The committees in each House of Congress to which a resolution has been referred under subsection (d)(3) shall conduct hearings on the Council's report and include in any report of the committee respecting such resolution the findings of the committee on the legal and factual sufficiency of any environmental impact statement submitted by the President relative to any system designated by him for approval.

(g)(1) At any time after a decision designating a transportation system is submitted to the Congress pursuant to this section, if the President finds that any provision of law applicable to actions to be taken under subsection (a) or (c) of section 9 require waiver in order to permit expeditious construction and initial operation of the approved transportation system, the President may submit such proposed waiver to both Houses of Congress.

(2) Such provision shall be waived with respect to actions to be taken under subsection (a) or (c) of section 9 upon enactment of a joint resolution pursuant to the procedures specified in subsections (c) and (d) of this section (other than subsection (d)(2) thereof) within the first period of 60 calendar days of continuous session of Congress beginning on the date after the date of receipt by the Senate and House of Representatives of such proposal.

(3) The resolving clause of the joint resolution referred to in this subsection is as follows: "That the House of Representatives and Senate approve the waiver of the provision of law (    ) as proposed by the President, submitted to the Congress on    , 19 ." The first blank space therein being filled with the citation to the provision of law and the second blank space therein being filled

with the date on which the President submits his decision to the House of Representatives and the Senate.

(4) In the case of action with respect to a joint resolution described in this subsection, the phrase "a waiver of a provision of law" shall be substituted in subsection (d) for the phrase "the Alaska natural gas transportation system.".

[15 U.S.C. 719f]

AUTHORIZATIONS

SEC. 9. (a) To the extent that the taking of any action which is necessary or related to the construction and initial operation of the approved transportation system requires a certificate, right-of-way, permit, lease, or other authorization to be issued or granted by a Federal officer or agency, such Federal officer or agency shall—

(1) to the fullest extent permitted by the provisions of law administered by such officer or agency, but

(2) without regard to any provision of law which is waived pursuant to section 8(g) issue or grant such certificates, permits, rights-of-way, leases, and other authorizations at the earliest practicable date.

(b) All actions of a Federal officer or agency with respect to consideration of applications or requests for the issuance or grant of a certificate, right-of-way, permit, lease, or other authorization to which subsection (a) applies shall be expedited and any such application or request shall take precedence over any similar applications or requests of the Federal officer or agency.

(c) Any certificate, right-of-way, permit, lease, or other authorization issued or granted pursuant to the direction under subsection (a) shall include the terms and conditions required by law unless waived pursuant to a resolution under section 8(g), and may include terms and conditions permitted by law, except that with respect to terms and conditions permitted but not required, the Federal officer or agency, notwithstanding any such other provision of law, shall have no authority to include terms and conditions as would compel a change in the basic nature and general route of the approved transportation system or those the inclusion of which would otherwise prevent or impair in any significant respect the expeditious construction and initial operation of such transportation system.

(d) Any Federal officer or agency, with respect to any certificate, permit, right-of-way, lease, or other authorization issued or granted by such officer or agency, may, to the extent permitted under laws administered by such officer or agency add to, amend or abrogate any term or condition included in such certificate, permit, right-of-way, lease, or other authorization except that with respect to any such action which is permitted but not required by law, such Federal officer or agency, notwithstanding any such other provision of law, shall have no authority to take such action if the terms and conditions to be added, or as amended, would compel a change in the basic nature and general route of the approved transportation system or would otherwise prevent or impair in any significant respect the expeditious construction and initial operation of such transportation system.

(e) Any Federal officer or agency to which subsection (a) applies, to the extent permitted under laws administered by such officer or agency, shall include in any certificate, permit, right-of-way, lease, or authorization issued or granted those terms and conditions identified in the President's decision as appropriate for inclusion except that the requirement to include such terms and conditions shall not limit the Federal officer or agency's authority under subsection (d) of this section.

[15 U.S.C. 719g]

JUDICIAL REVIEW

SEC. 10. (a) Notwithstanding any other provision of law, the actions of Federal officers or agencies taken pursuant to section 9 of this Act, shall not be subject to judicial review except as provided in this section.

(b)(1) Claims alleging the invalidity of this Act may be brought not later than the 60th day following the date a decision takes effect pursuant to section 8 of this Act.

(2) Claims alleging that an action will deny rights under the Constitution of the United States, or that an action is in excess of statutory jurisdiction, authority, or limitations, or short of statutory right may be brought not later than the 60th day following the date of such action, except that if a party shows that he did not know of the action complained of, and a reasonable person acting in the circumstances would not have known, he may bring a claim alleging the invalidity of such action on the grounds stated above not later than the 60th day following the date of his acquiring actual or constructive knowledge of such action.

(c)(1) A claim under subsection (b) shall be barred unless a complaint is filed prior to the expiration of such time limits in the United States Court of Appeals for the District of Columbia acting as a Special Court. Such court shall have exclusive jurisdiction to determine such proceeding in accordance with the procedures hereinafter provided, and no other court of the United States, of any State, territory, or possession of the United States, or of the District of Columbia, shall have jurisdiction of any such claim in any proceeding instituted prior to or on or after the date of enactment of this Act.

(2) Any such proceeding shall be assigned for hearing and completed at the earliest possible date, shall, to the greatest extent practicable, take precedence over all other matters pending on the docket of the court at that time, and shall be expedited in every way by such court and such court shall render its decision relative to any claim within 90 days from the date such claim is brought unless such court determines that a longer period of time is required to satisfy requirements of the United States Constitution.

(3) The enactment of a joint resolution under section 8 approving the decision of the President shall be conclusive as to the legal and factual sufficiency of the environmental impact statements submitted by the President relative to the approved transportation system and no court shall have jurisdiction to consider questions

respecting the sufficiency of such statements under the National Environmental Policy Act of 1969.

[15 U.S.C. 719h]

SUPPLEMENTAL ENFORCEMENT AUTHORITY

SEC. 11. (a) In addition to remedies available under other applicable provisions of law, whenever any Federal officer or agency determines that any person is in violation of any applicable provision of law administered or enforceable by such officer or agency or any rule, regulation, or order under such provision, including any term or condition of any certificate, right-of-way, permit, lease or other authorization, issued or granted by such officer or agency, such officer or agency may—

(1) issue a compliance order requiring such person to comply with such provision or any rule, regulation, or order thereunder, or

(2) bring a civil action in accordance with subsection (c).

(b) Any order issued under subsection (a) shall state with reasonable specificity the nature of the violation and a time or compliance not to exceed 30 days, which the officer or agency, as the case may be, determines is reasonable, taking into account the seriousness of the violation and any good faith efforts to comply with applicable requirements.

(c) Upon a request of such officer or agency, as the case may be, the Attorney General may commence a civil action for appropriate relief, including a permanent or temporary injunction or a civil penalty not to exceed $25,000 per day for violations of the compliance order issued under subsection (a). Any action under this subsection may be brought in any district court of the United States for the district in which the defendant is located, resides, or is doing business, and such court shall have jurisdiction to restrain such violation, require compliance, or impose such penalty or give ancillary relief.

[15 U.S.C. 719i]

EXPORT LIMITATIONS

SEC. 12. Any exports of Alaska natural gas shall be subject to the requirements of the Natural Gas Act and section 103 of the Energy Policy and Conservation Act, except that in addition to the requirements of such Acts, before any Alaska natural gas in excess of 1,000 Mcf per day may be exported to any nation other than Canada or Mexico, the President must make and publish an express finding that such exports will not diminish the total quantity or quality nor increase the total price of energy available to the United States.

[15 U.S.C. 719j]

EQUAL ACCESS TO FACILITIES

SEC. 13. (a) There shall be included in the terms of any certificate, permit, right-of-way, lease, or other authorization issued or granted pursuant to the directions contained in section 9 of this Act, a provision that no person seeking to transport natural gas in the Alaska natural gas transportation system shall be prevented from doing so or be discriminated against in the terms and conditions of service on the basis of degree of ownership, or lack thereof, of the Alaska natural gas transportation system.

(b) The State of Alaska is authorized to ship its royalty gas on the approved transportation system for use within Alaska and, to the extent its contracts for the sale of royalty gas so provide, to withdraw such gas from the interstate market for use within Alaska; the Federal Power Commission shall issue all authorizations necesssary to effectuate such shipment and withdrawal subject to review by the Commission only of the justness and reasonableness of the rate charged for such transportation.

[15 U.S.C. 719k]

ANTITRUST LAWS

SEC. 14. Nothing in this Act, and no action taken hereunder, shall imply or effect an amendment to, or exemption from, any provision of the antitrust laws.

[15 U.S.C. 719l]

AUTHORIZATION

SEC. 15. There is hereby authorized to be appropriated beginning in fiscal year 1978 and each fiscal year thereafter, such sums as may be necessary to carry out the functions of the Federal inspector appointed by the President with the advice and consent of the Senate under section 7.

[15 U.S.C. 719m]

SEPARABILITY

SEC. 16. If any provision of this Act, or the application thereof, is held invalid, the remainder of this Act shall not be affected thereby.

[15 U.S.C. 719n]

CIVIL RIGHTS

SEC. 17. All Federal officers and agencies shall take such affirmative action as is necessary to assure that no person shall, on the grounds of race, creed, color, national origin, or sex, be excluded from receiving, or participating in any activity conducted under, any certificates, permit, right-of-way, lease, or other authorization granted or issued pursuant to this Act. The appropriate Federal officers and agencies shall promulgate such rules as are necessary to carry out the purposes of this section and may enforce this section, and any rules promulgated under this section through agency and department provisions and rules which shall be similar to those established and in effect under title VI of the Civil Rights Act of 1964.

[15 U.S.C. 719o]

REPORT ON THE EQUITABLE ALLOCATION OF NORTH SLOPE CRUDE OIL

SEC. 18. Within 6 months of the date of enactment of this Act, the President shall determine what special expediting procedures are necessary to insure the equitable allocation of north slope crude oil to the Northern Tier States of Washington, Oregon, Idaho, Montana, North Dakota, Minnesota, Michigan, Wisconsin, Illinois, Indiana, and Ohio (hereinafter referred to as the "Northern Tier States") to carry out the provisions of section 410 of Public Law 93-153 and shall report his findings to the Congress. In his report, the President shall identify the specific provisions of law, which relate to any determination of a Federal officer or agency as to whether to issue or grant a certificate, permit, right-of-way, lease, or other authorization in connection with the construction of an oil delivery system serving the Northern Tier States and which the President finds would inhibit the expeditious construction of such a system in the contiguous States of the United States. In addition the President will include in his report a statement which demonstrates the impact that the delivery system will have on reducing the dependency of New England and the Middle Atlantic States on foreign oil imports. Furthermore, all Federal officers and agencies shall, prior to the submission of such report and further congressional action relating thereto, expedite to the fullest practicable extent all applications and requests for action made with respect to such an oil delivery system.

[43 U.S.C. 1651 note]

ANTITRUST STUDY

SEC. 19. The Attorney General of the United States is authorized and directed to conduct a thorough study of the antitrust issues and problems relating to the production and transportation of Alaska natural gas and, not later than six months following the date of enactment of this Act, to complete such study and submit to the Congress a report containing his findings and recommendations with respect thereto.

[15 U.S.C. 719 note]

EXPIRATION

SEC. 20. This Act shall terminate in the event that no decision of the President takes effect under section 8 of this Act, such termination to occur at the end of the last day on which a decision could be, but is not, approved under such section.

[15 U.S.C. 719 note]

## ALASKA NATURAL GAS TRANSPORTATION SYSTEM: PRESIDENTIAL DECISION

**Presidential Decision Designating Transportation System.**—On September 22, 1977, the President submitted a decision and report to the Congress designating the Alaska Highway Pipeline route for the Alaska natural gas pipeline system. The President's decision was approved by Public Law 95–158 (Nov. 8, 1977; 91 Stat. 1268), adopted under section 8 of the Alaska Natural Gas Transportation Act of 1976.

*To the Congress of the United States:*

Natural gas has become the Nation's scarcest and most desired fuel. It is in our interest to bring the reserves in Alaska to market at the lowest possible price. Consequently, I am today sending the Congress my decision and report on an Alaska Natural Gas Transportation System.

The selection of the Alcan project was made after an exhaustive review required by the Alaska Natural Gas Transportation Act of 1976 determined that the Alcan Pipeline System will deliver more natural gas at less cost to a greater number of Americans than any other proposed transportation system.

The Alcan proposal, taken together with the recently signed Agreement on Principles with Canada, demonstrates that our two countries working together can transport more energy more efficiently than either of us could transport alone.

Unnecessary delay would greatly increase the total cost of the pipeline system. I urge the Congress to act expeditiously to approve this important project.

JIMMY CARTER.

THE WHITE HOUSE, *September 22, 1977.*

## CONTENTS

## OVERVIEW

In the winter of 1967–68 a wildcat rig drilling Prudhoe Bay State Well No. 1 struck a formation that, when later delineated, proved to be the largest petroleum reserve on the North American continent. The Prudhoe Bay field contains over 20 trillion cubic feet of saleable natural gas and more than 9 billion barrels of recoverable oil. This gas represents approximately 10 percent of the known gas reserves in the United States.

In 1969, the State of Alaska held a lease sale and received almost $1 billion in lease bonuses. Shortly thereafter, the three major leaseholders in the Prudhoe Bay Oil Pool announced their intention to build an oil pipeline through Alaska from Prudhoe Bay to a site on the Gulf of Alaska. After an initial flurry of activity, the Trans-Alaskan Pipe Line System (TAPS) became entangled in legal disputes until November of 1973, when the Congress and President approved the plan and provided for expedited procedures. Construction was started immediately thereafter and the first flow of oil through the pipeline commenced on June 20, 1977.

Another set of studies began in 1969 which eventually resulted in applications to the Federal Power Commission (FPC) in the U.S. and the National Energy Board (NEB) in Canada for a certificate to construct a pipeline to move Alaskan and Mackenzie Delta gas to United States and Canadian markets, respectively, by Arctic Gas (Alaskan Arctic Gas Pipeline Company and Canadian Arctic Gas Pipeline Limited) in March 1974.

In September 1974, El Paso Alaska Company filed an application to transport Prudhoe Bay gas by a pipeline adjacent to TAPS to the Gulf of Alaska, liquefy it, and ship it to California by LNG tanker. There the LNG would be regasified and provided to its purchasers either directly or by displacement through existing pipeline facilities.

Under the Trans-Alaska Pipeline Act, Congress had authorized and requested the President to determine the willingness of the Government of Canada to authorize a natural gas pipeline for Alaska gas across Canada and whether intergovernmental agreements would be needed to achieve that end. After discussions, the Government of Canada indicated they were prepared to consider an agreement of general applicability as opposed to an agreement on a specific pipeline. Negotiations on a Transit Pipeline Treaty were undertaken, and a treaty was finally signed on January 28, 1977, and entered into force on September 19, 1977. It will govern all existing and future transit pipelines in the two countries for thirty-five years.

On April 7, 1975, a proceeding before FPC Administrative Law Judge Nahum Litt was initiated and over 45,000 pages of testimony and more than 1,000 supporting exhibits were compiled before it was concluded. Similar hearings were held by the NEB in Canada.

On July 9, 1976, Alcan Pipeline Company and Northwest Pipeline Company (Alcan) filed the third application with the FPC for a certificate to transport Alaskan gas. The Alcan plan, as modified in March 1977, calls for a pipeline following existing utility corridors from Prudhoe Bay through Canada to the U.S. markets.

Recognizing the shortages of natural gas, the large reserves of natural gas in Alaska, the benefits resulting from the expeditious construction of a transportation system for that gas, and the potentials for delay inherent in the normal regulatory approach to a project of this magnitude, on October 22, 1976, Congress passed the Alaska Natural Gas Transportation Act of 1976 (ANGTA). Designed to draw upon all relevant governmental, public and private expertise in reaching a Presidential and Congressional decision on construction of the best possible Alaska natural gas transportation system, if any, the statute established a unique process for reaching an expedited decision.

This *Decision* and *Report on an Alaska Natural Gas Transportation System* meets the statutory decision-making requirements of the Alaska Natural Gas Transportation Act and represents the culmination of the Executive Branch function in the process established by the Bill.

The Act's Statement of Purpose clearly sets out the Congressional objectives:

"SEC. 3. The purpose of this Act is to provide the means for making a sound decision as to the selection of a transportation system for delivery of Alaska natural gas to the contiguous States for construction and initial operation by providing for the participation of the President and the Congress in the selection process, and, if such a system is approved under this Act, to expedite its construction and initial operation by (1) limiting the jurisdiction of the courts to review the actions of Federal officers or agencies taken pursuant to the direction and authority of this Act, and (2) permitting the limitation of administrative procedures and effecting the limitation of judicial procedures related to such actions. To accomplish this purpose it is the intent of the Congress to exercise its Constitutional powers to the fullest extent in the authorizations and directions herein made, and particularly with respect to the limitation of judicial review of actions of Federal officers or agencies taken pursuant thereto."

Shortly after the passage of ANGTA, Judge Litt concluded the FPC hearing and on February 1, 1977 issued the Initial Decision favoring the Arctic proposal. According to the provisions in the Act, on May 2, 1977, the FPC made its *Recommendation to the President* in which it recommended an overland route through Canada but divided 2–2 on the choice between Alcan and Arctic Gas.

As required in the Act, comments on the *Recommendation* of the FPC were made to the President on July 1, 1977, by ten interagency task forces and a wide spectrum of non-Federal government officials and other interested persons. While generally supportive of the FPC *Recommendation*, they raised important questions regarding virtually every major element of the *Recommendation*.

On July 4, 1977, Canada's NEB made its decision regarding an overland pipeline system through Canada. It found the Arctic Gas proposal "environmentally unacceptable" and stated it was prepared to certify Alcan conditioned upon several modifications of the Alcan system recommended by the FPC. Within a few weeks, an interagency group of U.S. negotiators began meeting with Canadian officials to explore the boundaries of the Canadian option to enable the President to make an informed decision under the Act.

On September 1, the President announced a deferral in transmitting the decision to the Congress to complete negotiations with the Canadians. After intensive negotiations, President Carter and Prime Minister Trudeau announced in Washington on September 8, that both countries had reached an agreement in principle on a joint project for the transportation of Alaskan and Canadian gas. The President and Prime Minister noted the superiority of a joint project to any unilateral undertaking by either government. In addition to announcing an intention to sign a formal Agreement on Principles concerning the project, both governments pledged to seek approval from their respective legislatures of expedited provisions for project construction and operation.

With the signing of the Agreement on Principles applicable to a Northern Natural Gas Pipeline in Ottawa on September 20, 1977, the President transmitted the *Decision* favoring the Alcan project to the Congress for its approval. The Congress has sixty legislative days within which to act upon a joint resolution of approval.

The Agreement on Principles, as incorporated in the *Decision* of the President, provides the framework for a clearly specified, economically efficient, and environmentally superior means of transporting both U.S. and Canadian gas to markets through a joint pipeline system. Approval of the *Decision*, which incorporates the Agreement on Principles, will provide the same type of commitment by the United States to this undertaking as will result from passage of the implementing legislation which Prime Minister Trudeau has announced will be submitted to Parliament in October.

This *Decision* is supported by a strong record and recommendation from the FPC, substantial comments from all parties of interest and a clear and cogent agreement with the Canadian government that provides significant benefits for both countries.

The proposed Alcan system will deliver Alaska gas at the lowest cost-of-service to U.S. consumers—probably below the cost of imported oil and substantially below the costs of other fuel alternatives. The average price of distillate from imported oil over the life of the project is expected to be in excess of $3 per million btu's (mmbtu) in constant 1975 dollars. The average delivered price of Alaska gas for the same period will be substantially less even with a significant allowance for cost overruns. The Alcan system will deliver Alaskan gas at the lowest cost to U.S. consumers, but will do so *directly* to both the Midwest and West Coast markets. Furthermore, the Alcan system will increase the ability of Canada to develop its own frontier gas reserves, particularly in the Mackenzie Delta, through connection of the proposed Dempster Highway lateral pipeline with the Alcan mainline from Alaska. If Mackenzie

Delta gas is brought to Canadian markets, U.S. consumers might also benefit from the enhanced availability of Canadian supplies.

Under almost all criteria, the Alcan system is clearly superior to the proposal by the El Paso Alaska Company to liquefy Alaska gas and ship it to the West Coast. Over a 20-year period, the Alcan system would deliver Alaska gas to U.S. consumers at a signifcantly lower average cost-of-service than El Paso. In 1975 constant dollars the 20-year average cost of service for Alcan is estimated to be $1.04 per mmbtu, and $1.21 per mmbtu for El Paso. This difference represents ultimate savings of $6 billion for American consumers over the life of the Alcan project. Alcan also can move the same volume of gas with a higher fuel efficiency, and will have much lower annual operating costs than the El Paso LNG system.

Alcan also has a markedly greater Net National Economic Benefit (NNEB) than El Paso. The calculation of the NNEB compares the present value of real resource expenditures for a project with the present value of future benefits. Alcan has an estimated NNEB of $5.77 billion, more than $1.1 billion higher than the estimated NNEB of El Paso.

In addition to these economic advantages, Alcan has significant technical and resource advantages over El Paso. These include:

The superiority of pipeline transportation over LNG transportation for the safest and most reliable delivery of gas, and for expansibility of capacity to deliver increased volumes from reserves other than the Prudhoe Bay Pool;

The substantial advantage of pipeline facilities over LNG facilities in having a useful life of over 40 years;

The need to anticipate future shipment of natural gas from the Gulf of Alaska which may require LNG deliveries to the West Coast, thus preserving LNG delivery potential on the West Coast.

Furthermore, virtually all Federal agencies and private parties that compared the two projects determined that the Alcan system is environmentally superior to El Paso.

The Agreement with Canada on the Alcan system assures the cost-of-service advantages of the Alcan proposal. The Agreement provides that the Alcan pipeline will follow the original Alcan Highway route, without the route diversion required by the NEB. This provision alone saves the U.S. consumer up to $600 million in initial construction costs, plus interest, or the 6 cents in cost of service that would have been added by the route diversion. In return, the U.S. agreed to pay a portion of the cost for an extension of the Dempster Lateral from Dawson to Whitehorse in the Yukon—if and when the lateral is built. This limited extension, or "spur," would connect the Dempster line with the main Alcan system. A higher capacity, more efficient system will be installed south of Whitehorse, with costs shared on a volumetric basis, to carry U.S. and Canadian volumes.

Significantly, under the Agreement, the U.S. share of costs for the "spur" from Dawson to Whitehorse is tied to the percent of actual cost overruns on the construction of the Alcan main line in Canada. This element of the Agreement creates a formidable incentive for Canada to minimize cost overruns on the construction of the Alcan line in Canada. In addition, the Agreement protects the Alcan pipeline from unfair or discriminatory taxes that might threaten the cost of service advantages of Alcan for U.S. consumers. The provisions in the Agreement provide a ceiling on the imposition of Yukon taxes, and supercede the previous NEB recommendation for a $200 million impact assistance payment from U.S. consumers to the Yukon. Any advance payment of tax by the pipeline will be treated as a loan to the government, to be paid back with interest from future tax revenues, but in no event will the loan affect the cost of service to U.S. consumers. The fixed level of overall tax is only a modest increase above the level of tax included in the original estimates for Alcan's cost of service, and has been fixed with reference to the tax regime applicable in Alaska.

In this Agreement, the United States and Canada both improved their positions from the original NEB decision, and achieved a reduction in the cost of service price of both Alaskan gas and Canadian gas from the MacKenzie Delta. The modified Alcan system will also:

Assist Canada to continue supplying gas exports under existing contracts by providing it with access to substantial Mackenzie Delta reserves;

Provide the opportunity to obtain additional gas at an earlier date by early construction of portions of the southern Canadian and lower 48 sections of Alcan, with delivery of gas from Alberta (where there is temporary excess supply) in advance of the delivery of Alaska gas;

Encourage exploration for new reserves and stimulate expansion of the gas industry in Canada, which might ultimately benefit U.S. consumers through the enhanced potential of Canadian supplies.

Furthermore, this joint U.S.-Canadian undertaking could result in significant cooperation with Canada on a variety of other energy issues, such as oil exchanges, pipelines and strategic reserves.

The Alcan project will be one of the largest—if not the largest—privately financed international business ventures of all time. The minimal risk of non-completion will be borne by the private financial markets. There will be no Federal debt guarantees, and consumers will not be required to bear any portion of the risks of non-completion.

The Federal Government, however, will have an expanded and significant role in monitoring and overseeing the construction of the project. By enforcement of the terms and conditions proposed herein and to be later specified, the Federal Inspector for the construction of the project will coordinate Federal involvement with the project, minimizing cost overruns, preventing management abuses, and facilitating the timely completion of construction. The U.S.-Canadian Agreement provides additional incentives to minimize cost overruns on construction in Canada. The Decision, including the Agreement, seeks to ensure that U.S. consumers will have the enormous benefit of new Alaskan gas supplies at a price significantly below that of alternative energy sources.

A superior project has now been selected as a result of a thorough decision making process involving all the resources of the Federal Government and a spirited competition between private alternatives. The nation sorely needs new sources of economically competitive natural gas. Now is clearly the time to approve the decision to undertake the final planning and construction of this cost-efficient system for bringing critical supplies of Alaska natural gas to U.S. markets.

# DECISION ON AN ALASKA NATURAL GAS TRANSPORTATION SYSTEM

## PREFACE—STATUTORY REQUIREMENTS FOR A DECISION ON AN ALASKA NATURAL GAS TRANSPORTATION SYSTEM

Section 7(a)(4) of the Alaska Natural Gas Transportation Act of 1976 (ANGTA) states:

If the President determines to designate for approval a transportation system for delivery of Alaska natural gas to the contiguous States, he shall in such decision—

(A) describe the nature and route of the system designated for approval;

(B) designate a person to construct and operate such a system, which person shall be the applicant, if any, which filed for a certificate of public convenience and necessity to construct and operate such system;

(C) identify those facilities, the construction of which, and those operations, the conduct of which, shall be encompassed within the term "construction and initial operation" for purposes of defining the scope of the directions contained in Section 9 of this Act, taking into consideration any recommendation of the Commission with respect thereto; and

(D) identify those provisions of law, relating to any determination of a Federal officer or agency as to whether a certificate, permit, right-of-way, lease, or other authorization shall be issued or be granted, which provisions the President finds (i) involve determinations which are subsumed in his decision and (ii) require waiver pursuant to section 8(g) in order to permit the expeditious construction and initial operation of the transportation system.

As part of these determinations, an Agreement on Principles concluded with the Government of Canada prescribes various terms and conditions applicable to the construction and operation of the pipeline. The Agreement on Principles is attached hereto as Section 7 of this Decision and made an integral part of the Decision by this reference.

With the incorporation of the aforesaid Agreement, and the finding that it is in the national interest to expeditiously undertake to construct an Alaska Natural Gas Transportation System, the system designation and related statutory determinations are as follows:

## SECTION 1—DESIGNATION OF PERSON TO CONSTRUCT AND OPERATE THE SYSTEM

The Alcan Pipeline Company, now a wholly owned subsidiary of Northwest Pipeline Corporation,[1] or its successor, is hereby designated to construct and operate the portion of the system within the State of Alaska.

The Northern Border Pipeline Company, a partnership consisting of subsidiaries or affiliates of Columbia Gas Transmission Corporation, Michigan-Wisconsin Pipeline Company, Natural Gas Pipeline Company of America, Northern Natural Gas Company, Panhandle Eastern Pipe Line Company, and Texas Eastern Transmission Corporation, or its successor, is hereby designated to construct and operate the portion of the system from the United States-Canada border near Monchy, Saskatchewan, to a point near Dwight, Illinois.

*The Alcan Pipeline Company, or its successor, and the Northern Border Pipeline, or its successor, shall be publicly held corporations or general or limited partnerships, open to ownership participation by all persons without discrimination, except producers of Alaskan natural gas.

The Pacific Gas Transmission Company is hereby designated to construct and operate the portion of the system from the United States/Canada border near Kingsgate, British Columbia, to the border between the States of California and Oregon.

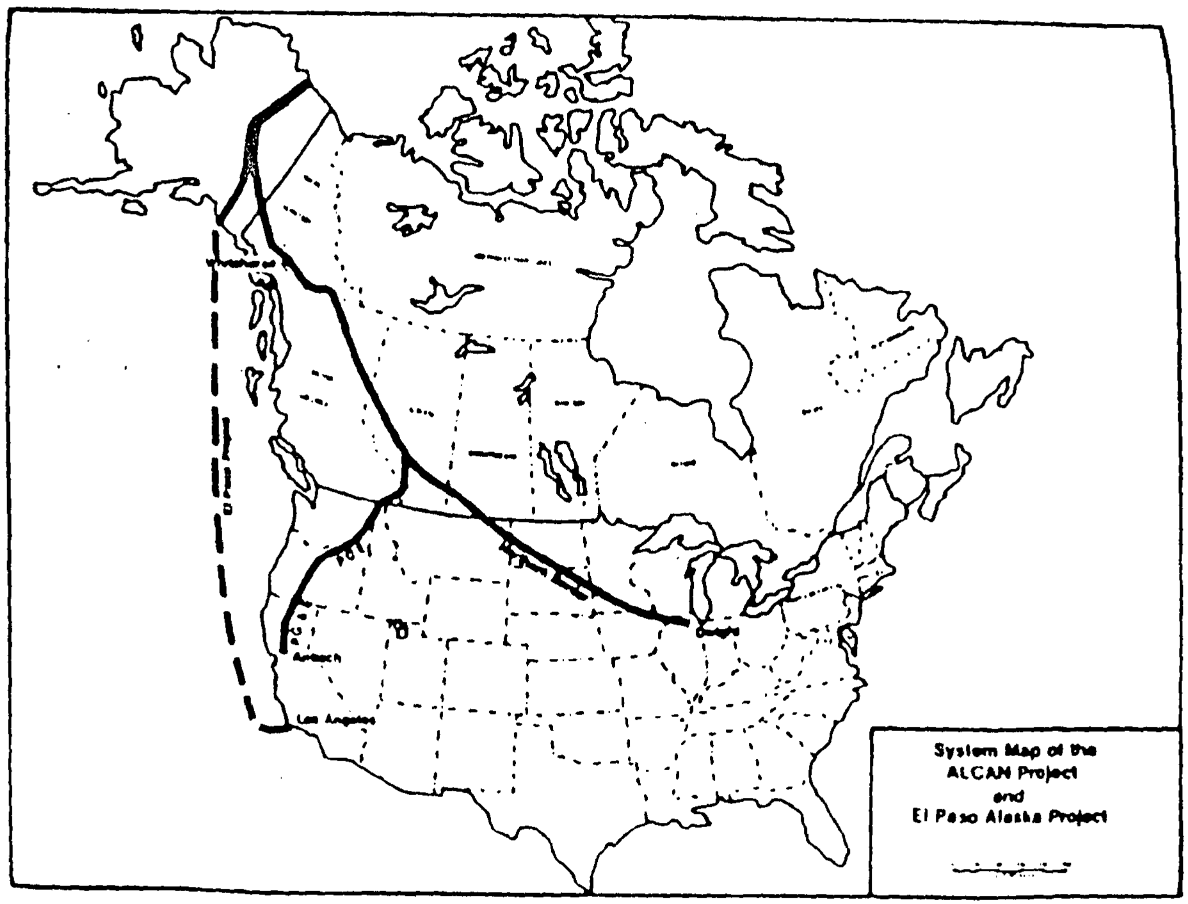
The Pacific Gas and Electric Company is hereby designated to construct and operate the portion of the system from the border between the States of California and Oregon through the State of California.

## SECTION 2—DESCRIPTION OF THE NATURE AND ROUTE OF THE APPROVED SYSTEM

The Alcan system is an overland pipeline system to transport natural gas from the Prudhoe Bay area of Northern Alaska through Alaska and Canada into the Midwest and Western sections of the contiguous United States. See Exhibit 1.

[1] Northwest Pipeline owns and operates a 4,300-mile pipeline system for transporting gas in the states of Colorado, Idaho, Nevada, Oregon, Utah, Washington, and Wyoming. Northwest Pipeline is a wholly-owned subsidiary of Northwest Energy Company, a holding company whose principal asset is all the outstanding common stock of Northwest Pipeline.

*This provision has been modified by Public Law 97-93 (Dec. 15, 1981; 95 Stat. 1204). The modification is set forth in the President's findings and proposed waivers of law, and is shown on page 334 of this volume of the compilation.


Antioch
Los Angeles
System Map of the
ALCAN Project
and
El Paso Alaska Project

The expected volume of gas to be available initially from the Prudhoe Bay field is 2.0 to 2.5 billion cubic feet per day (bcfd). The system described herein is designed to handle this throughput volume. The capacity of the system could be increased in the future to accommodate additional volume throughput by construction of additional facilities.

### ALCAN PIPELINE ROUTE IN ALASKA

*The proposed Alcan pipeline will commence at the discharge side of the gas plant facilities in the Prudhoe Bay field. The pipeline will parallel the Alyeska oil pipeline southward from the North Slope of Alaska, cross the Brooks Range through the Antigun Pass, and continue on to Delta Junction.

At Delta Junction, the Alcan Pipeline will diverge from the Alyeska oil pipeline and follow the Alaska Highway and the Haines oil products pipeline right-of-way, passing near the towns of Tanacross, Tok, and Northway Junction in Alaska. The right-of-way of the Haines oil products pipeline is at present approximately fifty feet wide and is closely parallel to the Alaska Highway. The Alcan pipeline will then connect with the proposed new facilities of Foothills Pipe Lines (South Yukon) Ltd. at the Alaska/Yukon Territory border.

From Prudhoe Bay in Delta Junction, Alcan expects to construct its line approximately eighty feet from the Alyeska oil pipeline. As proposed by Alcan, construction will be carried out by extending the existing Alyeska work pads. However, Alyeska advised Alcan that its "Preliminary general guidelines" indicated that the Alyeska and Alcan lines must be separated by 100 to 200 feet where blasting to build the pipeline trench would occur (approximately 350 miles of pipeline length). Additional studies will determine the minimum distance between the Alyeska oil pipeline and the Alcan line that is necessary to permit safe construction and operation.

### ALCAN PIPELINE ROUTE THROUGH CANADA

The Canadian portion of the Alcan Project will commence at the Alaska/Yukon border in the vicinity of the towns of Border City, Alaska and Boundary, Yukon.

From the Alaska/Yukon border, the Foothills Pipe Lines (South Yukon) Ltd. pipeline will proceed south until it reaches the White River (Milepost 44), where it will take a more eastward course across the Yukon Territory. The piepline will cross the Territory generally parallel to the Alaska Highway. Along most of the pipeline route through the Yukon, the separation between the pipeline route and highway route will be approximately one mile. There will be several points, however, where the pipeline route will divert substantially from the route of the Alaska Highway. These departures from the Alaska Highway route will permit the pipeline to continue on a more direct course than if it were to follow the Alaska Highway

*This provision has been modified by Public Law 97-93 (Dec. 15, 1981; 95 Stat. 1204). The modification is set forth in the President's findings and proposed waivers of law, and is shown on page 334 of this volume of the compilation.

At approximately milepost 246, the pipeline will be routed north of Whitehorse and cross the Yukon River near the intersection of the Alaska and Klondike Highways. Near this intersection, approximately 9 miles northwest of Whitehorse, the pipeline will be constructed to permit a later connection with the proposed Dempster Line from the Mackenzie Delta, if and when the Dempster Line is constructed.

After it crosses the Yukon River north of Whitehorse, the pipeline will turn southeast and again travel parallel to the Alaska Highway, entering British Columbia at approximately milepost 397 and reentering the Yukon Territory at approximately milepost 435. The pipeline will continue to follow the Alaska Highway eastward through the Yukon Territory and again cross the border into British Columbia, approximately twelve miles southwest of Watson Lake, Yukon. At this point, the Foothills Pipe Lines (South Yukon) Ltd. pipeline will terminate, and the Foothills Pipe Line (North B.C.) Ltd, interconnecting pipeline will commence.

After it passes the British Columbia border, the pipeline will proceed generally southeast across the northeastern part of the Province to the British Columbia/Alberta border, crossing the existing Westcoast Transmission Company Ltd. main line some 35 miles south of Fort Nelson. At Boundary Lake on the British Columbia-Alberta border, the pipeline would connect with the Foothills Pipe Lines (Alta.) Ltd. pipeline. In Alberta, the Foothills Pipe Lines (Alta.) Ltd. pipeline will proceed generally southeast from Boundary Lake to Gold Creek Junction. After Gold Creek Junction, the pipeline will follow the existing Alberta Gas Trunkline Co., Ltd. (AGTL) pipeline right-of-way to James River Station.

From James River Station, the western leg of the pipeline will proceed separately to the south, approximately following the existing AGTL right-of-way to the Alberta/British Columbia border near Coleman, Alberta. It will then connect with the Foothills Pipelines (South B.C.) Ltd. pipeline, continue to the southwest across British Columbia, and finally connect with the Pacific Gas Transmission (PGT) pipeline at the United States/Canada border near Kingsgate, British Columbia. The pipeline route through southern British Columbia will generally parallel the existing pipeline route of Alberta Natural Gas Company, Ltd.

For the eastern leg from James River Station, the pipeline will proceed generally to the southeast until it reaches the Alberta/Saskatchewan border near Empress, Alberta. The eastern leg will then connect with the Foothills Pipe Lines (Sask.), Ltd. pipeline. The pipeline will then continue to the southeast across Saskatchewan and join with the Northern Border Pipeline system at the United States/Canada border near Monchy, Saskatchewan.

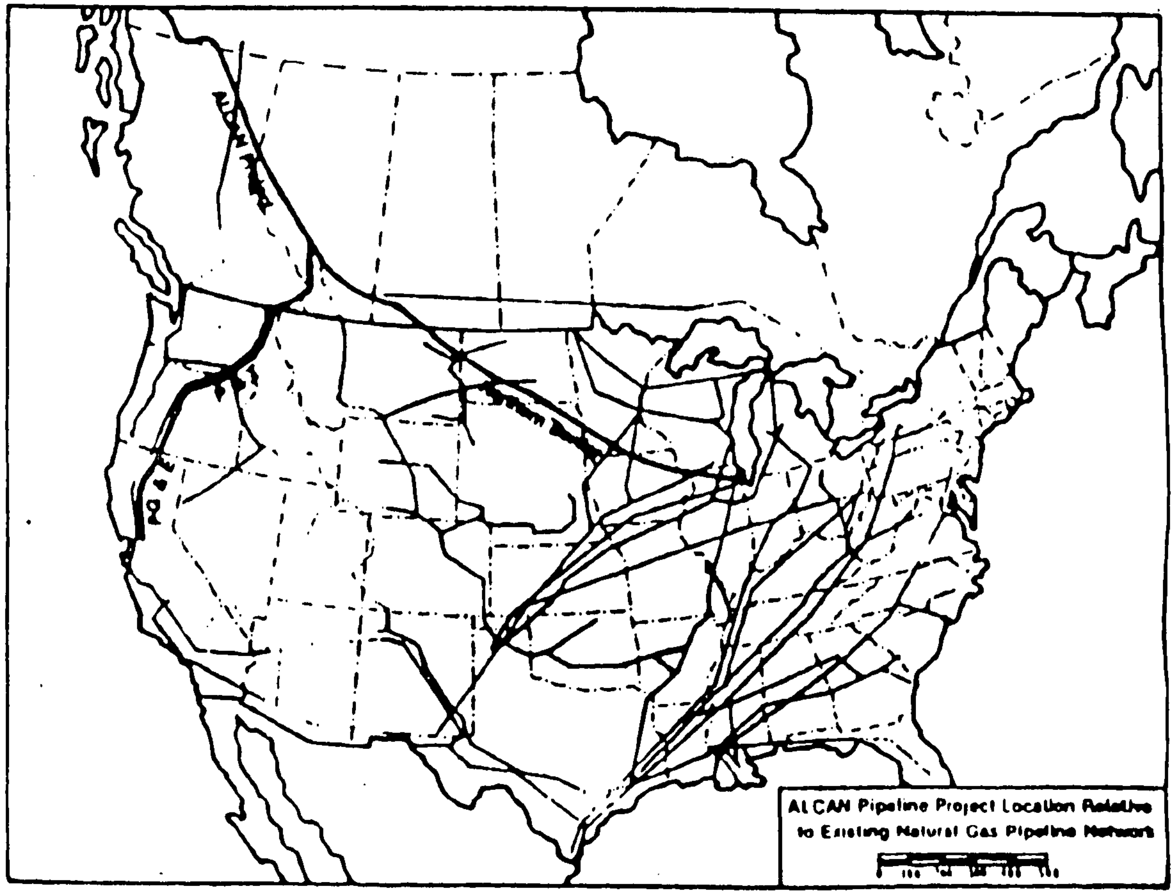
ALCAN PIPELINE ROUTE IN THE CONTIGUOUS UNITED STATES

On the western leg, the Alaska gas will be transferred at the United States-Canada border near Kingsgate, British Columbia, to the PGT system. The PGT system will transport the gas through northern Idaho, southeast Washington, and central Oregon. At the Oregon/California border, the gas will be transferred to enter the

Pacific Gas and Electric Company (PG&E) system and will then be transported throughout California.

On the eastern leg the Alaska gas will be transferred at the Saskatchewan/Montana border from the Canadian-owned portion of the Alcan system to the Northern Border Pipeline system. The Northern Border Pipeline system will then transport the gas across the northeast corner of Montana, the southwest section of North Dakota, the northeast section of South Dakota, the southwest corner of Minnesota, and the northeast section of Iowa, and finally bring the gas just south of Chicago to Dwight, Illinois.

Exhibit 2 on the following page illustrates the respective routes of the eastern and western legs of the Alcan system and their relationship to the existing gas pipeline network in the United States.



ALCAN Pipeline Project Location Relative to Existing Natural Gas Pipeline Network

## SECTION 3—IDENTIFICATION OF FACILITIES INCLUDED WITHIN "CONSTRUCTION AND INITIAL OPERATION"

### GENERAL PROJECT DESCRIPTION

This section identifies the facilities for the Alcan project which will be entitled to the expedited authorization process prescribed in Section 9 of ANGTA. The facilities which are to be covered are those in the U.S. which are adequate for a throughput of up to 2.4 bcfd and are included in the revised Alcan filing submitted to the Federal Power Commission (FPC) in March 8, 1977. If any modifications to those facilities are required by the Agreement on Principles between the U.S. and Canada, those modified facilities will also be entitled to the expedited authorization process in Section 9.

Uncertainties remain as to the future level of gas exports from Canada's historical gas supply sources. The actual division of Alaska gas among the various regions of the contiguous United States awaits conclusion of gas sales contracts. Routing and design work should be sufficiently complete to allow final certification in late 1978 or early 1979. The final design and location of the facilities, however, will be within the general description set forth.

The gas transportation system will utilize a 48-inch diameter pipeline from Prudhoe Bay to James River, Alberta. From James River, gas destined for the midwestern and eastern states will be transported through a 42-inch diameter pipeline to Monchy, Saskatchewan, and gas destined for the western states will be transported through a 36-inch pipeline to Kingsgate, British Columbia. PGT and PG&E will complete looping[2] as necessary of their existing pipeline systems from the Idaho-British Columbia border to Antioch, California (near San Francisco) with a 36-inch diameter pipeline.

All of the pipeline in Alaska and the first forty-one miles of pipeline in the Yukon lie in the continuous and discontinuous permafrost region.[3] This section will be operated in a chilled state (i.e., below 32°F.) to prevent degradation of the permafrost regime. Gas chilling will be accomplished by propane refrigeration systems at all compressor stations in Alaska.

The length of the various pipeline segments will be as follows:

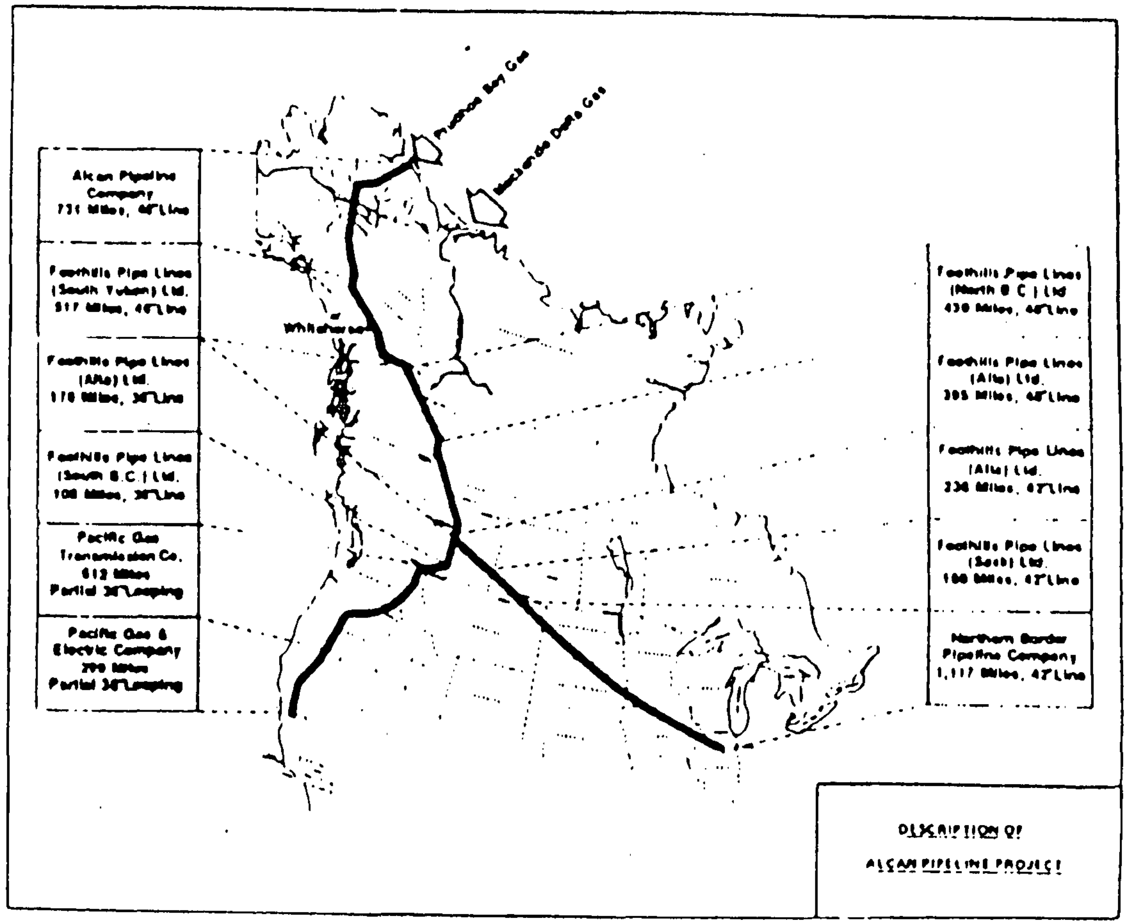
| Company and Location: | Length (miles) |
|---|---|
| Alcan Pipeline Co.—Alaska | 731 |
| Foothills Pipe Lines (South Yukon) Ltd.—Yukon | 517 |
| Foothills Pipe Lines (Sask.) Ltd—Saskatchewan | 160 |
| Foothills Pipe Lines (North B.C.) Ltd.—Yukon/B.C. Border to B.C./Alberta Border | 439 |
| Foothills Pipe Lines (South B.C.) Ltd.—Coleman to Kingsgate | 106 |

[2] "Looping" is construction of a pipeline parallel to and interconnected with an existing pipeline. Looping may extend to part or all of an existing line.

[3] By definition, permafrost consists of soil, rock, or other earth material, the temperature of which remains at or below 32°F. (0°C) continuously for two or more years. Its distribution is not uniform. Factors controlling the distribution of permafrost include the glacial and climatic history of the area, thermal properties of the earth material, ambient temperature, insulation properties of overburden, and amount of exposure to sun (e.g., shading caused by orientation of topographic features). The permafrost would be continuous along approximately the first 240 miles of the pipeline (to near the South Fork of the Koyukuk River). Along the remaining pipeline route to the Yukon border, the permafrost would be discontinuous.

| | Length (miles) |
|---|---|
| Foothills Pipe Lines (Alta.) Ltd.: | |
| B.C./Alberta to James River | 395 |
| James River to Coleman | 176 |
| James River to Empress | 235 |
| Total Alaska and Canada | 2,759 |
| Pacific Gas Transmission Co.—Kingsgate to Malin | 612 |
| Pacific Gas & Electric Co.—Malin to Antioch | 299 |
| Northern Border Pipeline Co.—Monchy to Dwight | 1,117 |
| Total contiguous States | 2,028 |
| Total system length | 4,787 |

Exhibit 3 on the next page identifies and locates the various pipeline segments.




DESCRIPTION OF ALCAN PIPELINE PROJECT

Peak-day capacity utilizing nine compressor stations (see item 4 below) will be 2.6 bcfd, with an average daily volume of 2.4 bcfd. By installation of intermediate compressor stations, the system could be increased to 3.4 bcfd peak capacity, with an average day capacity of 3.2 bcfd. The system capacity could be further increased by addition to the compressor horsepower at each station.

ALCAN COMPRESSOR STATIONS AND REFRIGERATION FACILITIES IN ALASKA

Centrifugal compressors, powered by natural gas-fueled turbine engines, will be used on the Alcan system. In order to minimize thawing of the permafrost soil, the discharge gas at each compressor station in Alaska will be chilled by a propane refrigeration plant. The following describes the required compression and refrigeration facilities. All of these facilities are required for construction and initial operation.

| Station | Milepost | Number of gas compressors | Total installed horsepower (ISO) | |
|---|---|---|---|---|
| | | | Gas compression | Gas refrigeration |
| AL-1 | 75.0 | 1 | 26,500 | 7,660 |
| AL-2 | 133.0 | 1 | 26,500 | 7,660 |
| AL-3 | 242.3 | 1 | 26,500 | 13,830 |
| AL-4 | 331.8 | 1 | 26,500 | 13,830 |
| AL-5 | 418.8 | 1 | 26,500 | 13,830 |
| AL-6 | 504.7 | 1 | 26,500 | 13,830 |
| AL-7 | 589.9 | 1 | 26,500 | 13,830 |
| AL-8 | 673.4 | 1 | 26,500 | 13,830 |
| Total | | 8 | 212,000 | 98,300 |

OTHER ALCAN PIPELINE FACILITIES IN ALASKA

Metering facilities for the measurement of gas flow and gas quality will be required in Alaska at the Prudhoe Bay receipt point, at the Fairbanks sales point, and at the transfer point on the Alaska-Yukon border.

A central operating center, located in Fairbanks, will monitor and control all compressor station operations.[4]

Alcan will utilize staging areas established for the Alyeska oil pipeline at Prudhoe Bay, Fairbanks, and Valdez. Material storage sites will be located at Anchorage, Seward, and Whittier, and at selected locations along the pipeline route.

Existing transportation and communication facilities will be utilized to the fullest extent practicable. Short lateral roads will be constructed to pipeline facilities as required.

Permanent bases for operating and maintaining the system will be selected and located after defining areas in which common problems may occur due to similarities of terrain and climate. The bases will be located at or near compressor stations to avoid duplication of permanent above-ground facilities. Materials and various

[4] The compressor stations will be automated for remote control of all normal functions, including discharge gas temperature.

spare parts will be located at the bases to facilitate maintenance and repair operations.

All of these facilities will be required for construction and initial operation.

LOWER 48 FACILITIES

For purposes of this part of the Decision, the facilities described generally below are deemed necessary for construction and initial operation, and will be entitled to expedited issuance of authorizations pursuant to section 9 of ANGTA, provided that the final certification of such facilities shall be determined by reference to the size necessary to provide the transportation capacity certified to the FPC[5] by the Secretary of Energy, as set forth in the terms and conditions section.

In order to deliver gas contemporaneously to points both east and west of the Rocky Mountains in the lower continental United States, the Alcan system will bifurcate at James River, Alberta and form a Western Leg and an Eastern Leg. First, the Western Leg is described below, and then the Eastern Leg.

### Western Leg

Alaskan gas will be transferred at the Canada/United States border near Kingsgate, British Columbia, to Pacific Gas Transmission Company (PGT). PGT will transport the gas through Idaho, Washington, and Oregon. At the Oregon/California border, the gas will enter the intrastate facilities of Pacific Gas and Electric Company (PG&E). The gas will be transported throughout much of California through existing and expanded intrastate gas pipelines.

The additional Western Leg facilities which are part of the Alcan project are those covered by the "1580 Design." The major component of this expansion will add approximately 873 miles of looping and result in complete looping of the 917-mile PGT/PG&E system from the Canada/United States border to Antioch, California (near San Francisco). The two parallel lines will be operated as a single system. Various modifications to the existing compression facilities will be required. However, the increase in system capacity of 659 mmcfd could be achieved without installation of additional compression horsepower or increase of compression fuel usage. A minor addition of facilities south of Antioch may be made at a later date, depending on conditions prevailing at that time. All Western Leg facilities which are part of the Alcan project are subject to Section 9 of ANGTA.

### The Eastern Leg

The Alcan system will transport Alaskan gas for delivery to Midwestern and Eastern markets in the lower continental United

[5] The final certification function currently resides with the Federal Power Commission under the Natural Gas Act. On October 1, 1977, the Department of Energy will be activated pursuant to the Department of Energy Organization Act, Public Law 95-91, and the functions of the FPC under the Natural Gas Act will be transferred in part to the Federal Energy Regulatory Commission (FERC). Therefore, where reference is made herein to future actions of the FPC, they will be carried out by either the Secretary or the FERC, as the case may be, as of October 1, 1977.

States through an Eastern Leg. The Eastern Leg will commence at the bifurcation point of the main express line at James River, Alberta and terminate at Dwight, Illinois (near Chicago). Total length of the Eastern Leg will be 1,352 miles, including 235 miles in Canada and 1,117 miles in the United States. All pipeline for the Eastern Leg will be 42 inches in diameter.

Alaskan gas will be transferred at the Saskatchewan/Montana border from the Canadian-owned portion of the Alcan system to the Northern Border Pipeline system (Northern Border). The Northern Border system will travel diagonally across Montana, North Dakota, South Dakota, Minnesota, and Iowa, and terminate near Chicago, Illinois. Along this route, direct deliveries of gas will be made by Northern Border into the systems which cross the pipeline: Natural Gas Pipeline Company of America, Northern Natural Gas Company, and Michigan-Wisconsin Pipeline Company. Other purchasers will receive Alaska gas by displacement.[6]

The specific facilities that will be required to interconnect the various pipelines to receive gas from the Northern Border system, either by direct delivery or by displacement, will be determined when gas sales contracts have been executed. Final design of the required facilities will depend upon the division of Alaskan gas among the various pipeline companies and various regions of the contiguous States. Final design will be complete at the time of final system certification in late 1978 or early 1979. All facilities which are part of the Northern Border system are necessary for construction and initial operation, and all facilities which are part of the Northern Border system as finally certified by the FPC are subject to Section 9 of ANGTA.

### SECTION 4—DELINEATION OF PROVISIONS OF LAW THAT ARE SUBSUMED IN THIS DECISION AND REQUIRE WAIVER

Under Section 7(a)(4)(D) of ANGTA, the President shall identify those provisions of law, relating to any determination of a Federal officer or agency as to whether a certificate, permit, right-of-way, lease, or other authorization shall be issued or be granted, which provisions the President finds (i) involve determinations which are subsumed in this decision and (ii) require waiver pursuant to section 8(g) in order to permit the expeditious construction and initial operation of the transportation system.

At this time, however, there are only two statutory provisions that involve determinations subsumed int his decision and require waiver pursuant to section 8(g) of ANGTA.[7]

Under Section 3 of the Natural Gas Act (15 U.S.C. 717b), the Federal Power Commission must issue an order to authorize any

[6] "Displacement" of gas is a method by which gas may be supplied to a purchaser from close by in exchange for gas sold to the purchaser elsewhere. Displacement, which is a commonly used method in the gas industry, eliminates the cost of physically transferring gas between markets.

[7] Section 8(g)(1) of ANGTA states that the President will have the opportunity at a later date to identify and seek waiver of additional provisions of law. This subsection states:

> At any time after a decision designating a transportation system is submitted to the Congress pursuant to this section, if the President finds that any provision of law applicable to actions to be taken under subsection (a) or (c) of section 9 require waiver in order to permit expeditious construction and initial operation of the approved transportation system, the President may submit such proposed waiver to both Houses of Congress.

export of natural gas; such an order shall issue unless the Commission finds that the export is not consistent with the public interest.

In addition, under Section 103 of the Energy Policy and Conservation Act, the President is required to promulgate a general rule prohibiting exports of natural gas from the U.S., except that he may permit those exports which he determines to be consistent with the national interest and with the purposes of the Act (Section 103(b)(1)). To make such a determination, Section 103(d)(1) directs the President to take into account the need to leave uninterrupted or unimpaired "exchanges in similar quantity for convenience or increased efficiency of transportation with persons or the government of a foreign state."

As a result of the recent Agreement on Principles between the United States and Canada, Alcan will be required to make available limited quantities of Alaskan gas to communities in the Yukon Territory and the western provinces, subject to provision of replacement gas downstream in Canada. This transaction will be an export requiring separate authorizations under the above mentioned two statutes.

The requirements arising under Section 3 of the Natural Gas Act and under Section 103 of the Energy Policy and Conservation Act could be met without waiver of these provisions, but additional, and unnecessary, FPC and Presidential action would be required. Accordingly, both of these statutory subsections shall be waived for the exchange of gas mentioned herein.

### SECTION 5—TERMS AND CONDITIONS AND ENFORCEMENT

To ensure the proper management and timely completion of the construction of the designated transportation system, the following general terms and conditions shall be appropriately incorporated into any certificate, right-of-way, lease, permit or authorization directed to be made by any Federal officer or agency.

As described more fully below, these terms and conditions will be followed by a set of stipulations establishing general standards of environmental and construction performance, and the procedures for the submission and approval of construction plans and environmental safeguards, and then by site specific terms and conditions issued prior to actual construction of any pipeline segment. The terms and conditions described here are not meant to limit or foreclose the adoption of such stipulations and terms and conditions but are intended to begin the process by which a set of effective and workable safeguards are evolved. There is contemplated cooperative action by the Federal and Alaska State Governments in the development and enforcement of stipulations and site specific terms and conditions. Similar cooperative action is contemplated with the governments of all affected states.

Under the proposal made at the end of this section for the organizational involvement of the Federal Government with the successful applicant, the Federal Inspector for construction of the transportation system shall have supervision authority over the enforcement of these terms and conditions subject to the ultimate authority of the Executive Policy Board described below.

## TERMS AND CONDITIONS

The terms and conditions proposed for inclusion into this Congressional authorization are set forth, by category, as follows:

### I. *Construction costs and schedule*

#### *Management and organization*

1. Prior to the issuance of the certificate, the successful applicant shall provide a detailed overall management plan, to be approved by the Federal Inspector, for the preconstruction and the construction phases of the transportation system project. The successful applicant shall define its relationship with the execution contractors, and shall give consideration to various management approaches—such as Fast Track Stage Design, and other management approaches—that will facilitate the cost-effective, environmentally sound, and timely construction of the project.

2. The successful applicant may not use cost-plus type contracts with execution contractors, except where the Federal Inspector determines that special conditions warrant this type of contract. Otherwise, the applicant shall use fixed-price contracts, including the firm fixed-price, the fixed-price with escalation, and fixed-price incentive type of contract.

3. The successful applicant shall specify for approval of the Federal Inspector the insurance, bonding, and any other prequalification requirements for all consultants and execution contractors.

#### Construction cost and schedule control techniques

4. Prior to the initiation of construction, the successful applicant shall provide a detailed analysis and description of its proposed cost and schedule control techniques. The applicant shall give particular consideration to cost and manpower control and manpower estimating techniques.

5. Prior to the initiation of construction, the successful applicant shall develop and submit to the Federal Inspector a final design, design-cost estimate, and construction schedule. This design cost estimate and schedule must represent a construction design of at least 70 percent (or greater) of the total system, and the remainder may not represent any one contiguous or specific type of construction or geologic situation (e.g., river crossings, discontinuous permafrost, or elevated pipeline). The Federal Inspector may relax the above specified minimum percentage requirement, with the consent of the Executive Policy Board, if he finds there are extenuating circumstances that warrant such an action.

#### General operating strategies

6. The successful applicant shall develop and submit to the Federal Inspector cost-effective and feasible methods for supplying general and specialized equipment, as well as repair facilities and spare-part inventories, to the execution contractors. The applicant shall give consideration to various techniques of equipment provision, including use of equipment pools, equipment leasing or buy-backs.

7. Prior to the initiation of construction, the successful applicant shall supply detailed information to the Federal Inspector on its labor relations procedures, and indicate the proposed means to address and resolve disputes arising under collective bargaining agreements.

8. In entering into contracts with execution contractors, the successful applicant shall seek to incorporate techniques for resolving disputes arising under such contracts without recourse to litigation.

Quality assurance and control procedures

9. The successful applicant shall provide to the Federal Inspector a detailed description of quality assurance and control procedures that will be implemented prior to the start of construction. Such a description must at least include provisions for quality assurance and control procedures for environmental protection, corrosion, pipeline and compressor-station welds, pipeline placement, equipment and other appropriate matters.

Procedures for enforcement of terms and conditions

10. The successful applicant may not initiate activity on any aspect of the pipeline until authorization to proceed with construction, including site-specific terms and conditions for that aspect of the pipeline, has been issued and procedures for enforcement of terms and conditions have been established by the appropriate Federal officers.

Minority business enterprise participation

11. The successful applicant shall develop and submit to the Federal Inspector for approval a plan for taking affirmative action to ensure that no person shall on the grounds of race, creed, color, national origin or sex be excluded from receiving or participating in contracts for management, engineering design or construction activity. The successful applicant shall require each of his contractors and subcontractors having contracts valued at $150,000 or more to develop similar plans providing the assurances specified in the preceding sentence.

II. *Safety and design*

1. The successful applicant shall construct, operate, maintain and terminate the pipeline in accordance with Federal gas pipeline safety regulations. The applicant shall ensure that construction and operating specifications are in accordance with good engineering practice, both to maintain the safety and the integrity of the pipeline and to protect the health and safety of project personnel and the general public.

2. The successful applicant may not begin construction of any pipeline segment until the Federal Inspector has approved the design of that segment, including technical construction specifications, having had sufficient time to review the design.

3. The successful applicant shall establish a procedure for briefing the Federal Inspector, or his designated representative, on a regular basis concerning the status of the project during the design, construction, testing and start-up phases.

4. The successful applicant shall establish a procedure to ensure access to all project facilities by the Federal Inspector, or his designated representative, in the performance of official duties.

5. The successful applicant shall submit a plan or procedure for conducting its own inspections of project facilities during construction, to be approved by the Federal Inspector.

6. The successful applicant shall provide a seismic monitoring system, to be approved by the Federal Inspector, and shall ensure that there are adequate procedures for the safe shut-down of the project under severe seismic conditions.

III. *Environment*

1. The successful applicant shall construct, operate, maintain and terminate the pipeline with maximum concern for the protection of environmental values. A set of stipulations containing the general standards of environmental and construction performance, and the procedures for the submission and approval of construction plans and environmental safeguards will be developed by the concerned government agencies and must be accepted by the applicant as a condition of his right to proceed over public lands. Additional "site-specific" terms and conditions will be incorporated in authorizations to proceed with construction issued by the appropriate Federal agency, into particular certificates, rights-of-way, permits and other authorizations to protect and enhance environmental values during the design, construction and operation of the pipeline. These additional "site specific" terms and conditions will be issued as appropriate to minimize disturbance from construction and operation of the pipeline to rivers and other water bodies and adjacent land and vegetation; to protect wildlife and endangered species and maintain forest, agricultural and other resource productivity; to control the risks of pipeline ruptures, leaks and hazards; to maintain air and water quality values; to make provision for control and disposal of sewage, garbage, wastes and toxic substances; and take other measures necessary for protection of the environment during the design, construction and operation of the pipeline.

2. The successful applicant shall prepare a plan of operations which integrates environmental protection with the proposed schedule of construction and operations, the proposed supervisory and technical staffing, the proposed quality control programs, and the proposed quality assurance programs. In preparation and implementation of this plan, the successful applicant shall provide for timely integration of environmental mitigation and restoration practices with the activity which creates the need for the restoration or mitigation.

3. The successful applicant shall develop and submit to the Federal Inspector an effective plan for implementation of specific environmental safeguards through an educational program for field personnel prior to and during construction, operation, maintenance and termination of the pipeline.

4. The successful applicant shall establish an effective pipeline-performance monitoring system of inspection and instrumentation to insure performance in keeping with environmental concerns.

IV. *Finance*

1. The successful applicant shall provide for private financing of the project, and shall make the final arrangement for all debt and equity financing prior to the initiation of construction.

*2. If the direct capital cost estimates excluding interest during construction for the overall project in 1975 constant dollars filed with the FPC immediately prior to certification, adjusted to reflect design changes to increase capacity that result from the Agreement on Principle between the United States and Canada, materially and unreasonably exceed the comparable capital cost estimates filed by Alcan with the Federal Power Commission on March 8, 1977, Section 6, page 2, the FPC may not issue a certificate for the project. If these final capital cost estimates are not excessive under the above standard, the FPC may use these final estimates for the U.S. segments as the basis for fixing a variable rate of return on equity that will reward the applicant for project completion under budgeted cost and penalize the applicant for project completion above budgeted cost. The variable return shall be set to provide substantial incentives to construct the project without incurring overruns. These final capital cost estimates need not be the design-cost estimates based on the system design which must subsequently be submitted to the Federal Inspector. The applicant shall, however, submit to the FPC for approval on a timely basis all components of construction work in progress.

*3. Neither the successful applicant nor any purchaser of Alaska gas for transportation through the system of the successful applicant shall be allowed to make use of any tariff by which or any other agreement by which the purchaser or ultimate consumer of Prudhoe Bay natural gas is compelled to pay a fee, surcharge, or other payment in relation to the Alaska natural gas transportation system at any time prior to competition and commissioning of operation of the system.

*4. The Alcan Pipeline Company, or its successor, and the Northern Border Pipeline, or its successor, shall be publicly held corporations or general or limited partnerships, open to ownership participation by all persons without discrimination, except producers of Alaskan natural gas.

V. *Antitrust*

*1. The successful applicant shall exclude and prohibit producers of significant amounts of Alaska gas, or their subsidiaries and affiliates, from participating in the ownership of the Alaska natural gas transportation system, except that such producers may provide guarantees for project debt. The aforesaid producers of Alaska gas may not be equity members of the sponsoring consortium, have any voting power in the project, have any role in the management or operations of the project, have any continuing financial obligation in relation to debt guarantees associated with initial project financing after the project is completed and the tariff is put into effect, or impose conditions on the guarantees of project debt permitted

*This provision has been modified by Public Law 97–93 (Dec. 15, 1981; 95 Stat. 1204). The modification is set forth in the President's findings and proposed waivers of law, and is shown on page 334 of this volume of the compilation.

above which may give rise to competitive abuse, including power to veto pro-competitive policies.

2. All agreements for the sale of Alaska gas made between the aforesaid producers and purchasers who are shippers through the Alaska natural gas transportation system shall be fully disclosed to the Federal Power Commission, and all collateral agreements made between the same parties with respect to the sale of Alaska gas shall also be fully disclosed. All contracts for sale of Alaska gas, for all collateral agreements to these contracts, shall be submitted for approval by the Federal Power Commission.

VI. *Certification of facilities*

1. Prior to the issuance of a certificate of public convenience and necessity to Northern Border Pipeline or to Pacific Gas Transmission Company, the Secretary of Energy shall certify to the Federal Power Commission whether there has been any material change in the facts regarding future potential gas supplies for the East or West since the date of this Decision that would warrant certification of such facilities at a different rated capacity than authorized herein. If the Secretary certifies that there has been a material change in the facts, he shall instead certify to the Commission the capacity at which he has determined a certificate of public convenience and necessity should be issued and the reasons therefor, which capacity shall be determined in a manner that is as consistent as possible with the reasons for the initial authorization, as set forth in the Report submitted to the Congress pursuant to Section 7(b) of the Alaska Natural Gas Transportation Act, Public Law 94–586. The certificate issued by the FPC shall be consistent with the Secretary's determination.

ENFORCEMENT

To enforce the terms and conditions proposed above, and to carry out the duties of the office assigned and set forth by section 7(a)(5)(A)–(E) of ANGTA, an appropriate and qualified individual shall be appointed by the President to serve as the Federal Inspector, with the advice and consent of the Senate. Upon approval of the Presidential designation of an Alaska natural gas transportation system, the Federal Inspector shall:

(A) establish a joint surveillance and monitoring agreement, approved by the President, with the State of Alaska similar to that in effect during construction of the trans-Alaska oil pipeline to monitor the construction of the approved transportation system within the State of Alaska;

(B) monitor compliance with applicable laws and the terms and conditions of any applicable certificate, rights-of-way, permit, lease, or other authorization issued or granted;

(C) monitor actions taken to assure timely completion of construction schedules and the achievement of quality of construction, cost control, safety, and environmental protection objectives and the results obtained therefrom;

(D) have the power to compel, by subpoena if necessary, submission of such information as he deems necessary to carry out his responsibilities; and

(E) keep the President and the Congress currently informed on any significant departures from compliance and issue quarterly reports to the President and the Congress concerning existing or potential failures to meet construction schedules or other factors which may delay the construction and initial operation of the system and the extent to which quality of construction, cost control, safety and environmental protection objectives have been achieved.

In addition to these duties and responsibilities, the President will submit to Congress, upon approval of the Presidential decision, a limited executive reorganization plan to transfer to the Federal Inspector field-level supervisory authority over enforcement of terms and conditions from those Federal agencies having statutory responsibilities over various aspects of an Alaska natural gas transportation system. The respective Federal agencies would retain their existing statutory authority pursuant to section 9(a) of ANGTA, to issue on an expedited basis the necessary certificates, permits, rights-of-way and other authorizations, and to prescribe any appropriate terms and conditions that are permissible under present law. The Agency Authorized Officers would directly represent the statutory authority of the respective Federal agencies in the field on all matters pertaining to construction of the pipeline. However, the Federal Inspector would have the necessary field-level supervisory authority to overrule the enforcement action of an Agency Authorized Officer, whenever the Federal Inspector determined that such a decision was warranted.

The President's supervision of the Federal Inspector will be carried out by an Executive Policy Board. The Board would be made up of the Secretaries of the Interior, Energy, Transportation, the Administrator of the Environmental Protection Agency, and the Chief of the Army Corps of Engineers, or their Deputies (or senior officers who have been delegated authority over gas pipeline matters), as well as the Federal Inspector, who is the non-voting Chairman of the Board. The Board will provide policy guidance to the Federal Inspector, and act as an appellate body to resolve differences among the agencies and the Federal Inspector, including differences that may arise when the Federal Inspector overrules an enforcement action of an Agency Authorized Officer. The Board shall expeditiously resolve any such appeal with a limited period of time that shall be prescribed. The President will authorize by Executive Order the creation of the Executive Policy Board pursuant to his power under Section 301 of Title 3, and will delegate the necessary authority to the Board to carry out its functions. The Board shall be paramount for policy-making purposes on all matters pertaining to construction of an Alaskan natural gas transportation system; the Federal Inspector shall be the agent or conduit of the Board in such matters, and shall also have the necessary supervisory power over field level decisions.

### SECTION 6—PRICING OF ALASKA GAS

Final financing for an Alaska natural gas transportation project cannot be arranged until the producer-owners of the Prudhoe Bay Gas execute sales contracts. Without such contracts, no gas can be transported, and financing consequently would be unobtainable. Producers cannot be expected to negotiate sales contracts until a price has been established with a reasonable degree of certainty. If this project is to proceed expeditiously, the field price of the gas should be established as soon as possible.

Because no contracts for gas sales in interstate commerce have been concluded and submitted to the FPC for approval, the FPC has not, to date, attempted to determine the costs of providing the gas in order to establish what might be a just and reasonable (cost-based) wellhead price. The FPC, in fact, has excluded the Alaska gas from its national rate proceedings; Alaska costs and related reserve data have been excluded from all statistics underlying FPC rate determinations.

Alaska gas is produced in association with oil; therefore, it is impossible to determine precisely the costs of finding, developing and producing only the gas. Cost allocation and, therefore, cost-based pricing is somewhat arbitrary. Because of the difficult and arbitrary nature of the allocation problem, the FPC in recent years has priced gas on the basis of the cost of only nonassociated gas in each producing area, and then allowed the same price to be paid for associated gas produced in that area as well. Were the FPC to initiate a price proceeding under the Natural Gas Act, it is expected that its procedures and subsequent litigation over cost allocation and other matters would likely exceed a period of 18 months.

The Administration's proposed National Energy Act is before the Congress. That Act provides a basis for moving from cost-based pricing to commodity-value pricing. That transition is essential to restoring the balance between natural gas supply and demand. Under the gas pricing provisions in the National Energy Plan, Alaska gas would be classified as "old gas under a new contract" subject to a $1.45 per mcf ceiling price.

If, on the other hand, proposals to deregulate natural gas prevail, serious uncertainties and delays concerning the development of any Alaska natural gas transportation project could result. If producers are inclined to insist on prices of $2.00 per mcf or higher, questions concerning the saleability of the gas and the financeability of the project will arise. Such price levels could result in an additional $20 billion in consumer charges, as well as the added costs of any delays in project construction.

This decision, therefore, calls for enactment of a gas pricing approach similar to that contained in the National Energy Plan. That approach also provides a mechanism for allocating the cost of more expensive supplies to lower-priority users, rather than the residential and commercial users who have less capacity to convert to other fuels. The gas pricing policies which are part of the National Energy Plan are fair and equitable, and should apply to both the production and sale of Alaska gas.

SECTION 7—AGREEMENT BETWEEN THE UNITED STATES OF AMERICA AND CANADA ON PRINCIPLES APPLICABLE TO A NORTHERN NATURAL GAS PIPELINE

The Government of the United States of America and the Government of Canada,

Desiring to advance the national economic and energy interests and to maximize related industrial benefits of each country, through the construction and operation of a pipeline system to provide for the transportation of natural gas from Alaska and from Northern Canada,

Hereby agree to the following principles for the construction and operation of such a system:

1. PIPELINE ROUTE

The construction and operation of a pipeline for the transmission of Alaska natural gas will be along the route set forth in Annex I, such pipeline being hereinafter referred to as "the Pipeline". All necessary action will be taken to authorize the construction and operation of the Pipeline in accordance with the principles set out in this Agreement.

2. EXPEDITIOUS CONSTRUCTION; TIMETABLE

(a) Both Governments will take measures to ensure the prompt issuance of all necessary permits, licenses, certificates, rights-of-way, leases and other authorizations required for the expeditious construction and commencement of operation of the Pipeline, with a view to commencing construction according to the following timetable:

Alaska—January 1, 1980.

Yukon—main line pipe laying January 1, 1981.

Other construction in Canada to provide for timely completion of the Pipeline to enable initial operation by January 1, 1983.

(b) All charges for such permits, licenses, certificates, rights-of-way, leases and other authorizations will be just and reasonable and apply to the Pipeline in the same nondiscriminatory manner as to any other similar pipeline.

(c) Both Governments will take measures necessary to facilitate the expeditious and efficient construction of the Pipeline, consistent with the respective regulatory requirements of each country.

3. CAPACITY OF PIPELINE AND AVAILABILITY OF GAS

(a) The initial capacity of the Pipeline will be sufficient to meet, when required, the contractual requirements of United States shippers and of Canadian shippers. It is contemplated that this capacity will be 2.4 billion cubic feet per day (bcfd) for Alaska gas and 1.2 bcfd for northern Canadian gas. At such time as a lateral pipeline transmitting Northern Canadian gas, hereinafter referred to as "the Dempster Line", is to be connected to the Pipeline or at any time additional pipeline capacity is needed to meet the contractual requirements of United States or Canadian shippers, the required authorizations will be provided, subject to regulatory requirements, to expand the capacity of the Pipeline in an efficient manner to meet those contractual requirements.

(b) The shippers on the Pipeline will, upon demonstration that an amount of Canadian gas equal on a British Thermal Unit (BTU) replacement value basis will be made available for contemporaneous export to the United States, make available from Alaska gas transmitted through the Pipeline, gas to meet the needs of remote users in the Yukon and in the provinces through which the Pipeline passes. Such replacement gas will be treated as hydrocarbons in transit for purposes of the Agreement between the Government of Canada and the Government of the United States of America concerning Transit Pipelines, hereinafter referred to as "the Transit Pipeline Treaty". The shippers on the Pipeline will not incur any cost for provision of such Alaska gas except those capital costs arising from the following provisions:

(i) the owner of the Pipeline in the Yukon will make arrangements to provide gas to the communities of Beaver Creek, Burwash Landing, Destruction Bay, Haines Junction, Whitehorse, Teslin, Upper Liard and Watson Lake at a total cost to the owner of the Pipeline not to exceed Canadian $2.5 million;

(ii) the owner of the Pipeline in the Yukon will make arrangements to provide gas to such other remote communities in the Yukon as may request such gas within a period of two years following commencement of operation of the Pipeline at a cost to the owner not to exceed the product of Canadian $2500 and the number of customers in the communities, to a maximum total cost of Canadian $2.5 million.

4. FINANCING

(a) It is understood that the construction of the Pipeline will be privately financed. Both Governments recognize that the companies owning the Pipeline in each country will have to demonstrate to the satisfaction of the United States or the Canadian Government, as applicable, that protections against risk of non-completion and interruption are on a basis acceptable to that Government before proof of financing is established and construction allowed to begin.

(b) The two Governments recognize the importance of constructing the Pipeline in a timely way and under effective cost controls. Therefore, the return on the equity investment in the Pipeline will be based on a variable rate of return for each company owning a segment of the Pipeline, designed to provide incentives to avoid cost overruns and to minimize costs consistent with sound pipeline management. The base for the incentive program used for establishing the appropriate rate of return will be the capital costs used in measuring cost overruns as set forth in Annex III.

(c) It is understood that debt instruments issued in connection with the financing of the Pipeline in Canada will not contain any provision, apart from normal trust indenture restrictions generally applicable in the pipeline industry, which would prohibit, limit or inhibit the financing of the construction of the Dempster Line; nor will the variable rate of return provisions referred to in subparagraph (b) be continued to the detriment of financing the Dempster Line.

5. TAXATION AND PROVINCIAL UNDERTAKINGS

(a) Both Governments reiterate their commitments as set forth in the Transit Pipeline Treaty with respect to non-discriminatory taxation, and take note of the statements issued by Governments of the Provinces of British Columbia, Alberta and Saskatchewan, attached hereto as Annex V, in which those Governments undertake to ensure adherence to the provisions of the Transit Pipeline Treaty with respect to non-interference with throughput and to non-discriminatory treatment with respect to taxes, fees or other monetary charges on either the Pipeline or throughput.

(b) With respect to the Yukon Property Tax imposed on or for the use of the Pipeline the following principles apply:

(i) The maximum level of the property tax, and other direct taxes having an incidence exclusively, or virtually exclusively, on the Pipeline, including taxes on gas used as compressor fuel, imposed by the Government of the Yukon Territory or any public authority therein on or for the use of the Pipeline, herein referred to as "the Yukon Property Tax", will not exceed $30 million Canadian per year adjusted annually from 1983 by the Canadian Gross National Product price deflator as determined by Statistics Canada, hereinafter referred to as the GNP price deflator.

(ii) For the period beginning January 1, 1980, and ending on December 31 of the year in which leave to open the Pipeline is granted by the appropriate regulatory authority, the Yukon Property Tax will not exceed the following:

1980—$5 million Canadian.
1981—$10 million Canadian.
1982—$20 million Canadian.

Any subsequent year to which this provision applies—$25 million Canadian.

(iii) The Yukon Property Tax formula described in subparagraph (b)(i) will apply from January 1 after the year in which leave to open the Pipeline is granted by the appropriate regulatory authority until the date that is the earlier of the following, hereinafter called the tax termination date:

(A) December 31, 2008, or

(B) December 31 of the year in which leave to open the Dempster Line is granted by the appropriate regulatory authority.

(iv) Subject to subparagraph (b)(iii), if for the year ending on December 31, 1987, the percentage increase of the aggregate per capita revenue derived from all property tax levied by any public authority in the Yukon Territory (excluding the Yukon Property Tax) and grants to municipalities and Local Improvement Districts from the Government of the Yukon Territory as compared to aggregate per capita revenue derived from such sources for 1983 is greater than the percentage increase for 1987 of the Yukon Property Tax as compared to the

Yukon Property Tax for 1983, the maximum level of the Yukon Property Tax for 1987 may be increased to equal the amount it would have reached had it increased over the period at the same rate as the aggregate per capita revenue.

(v) If for any year in the period commencing January 1, 1988, and ending on the tax termination date, the annual percentage increase of the aggregate per capita revenue derived from all property tax levied by any public authority in the Yukon Territory (excluding the Yukon Property Tax) and grants to municipalities and Local Improvement Districts from the Government of the Yukon Territory as compared to the aggregate per capita revenue derived from such sources for the immediately preceding year exceeds the percentage increase for that year of the Yukon Property Tax as compared to the Yukon Property Tax for the immediately preceding year, the maximum level of the Yukon Property Tax for that year may be adjusted by the percentage increase of the aggregate per capita revenue in place of the percentage increase that otherwise might apply.

(vi) The provisions of subparagraph (b)(i) will apply to the value of the Pipeline for the capacities contemplated in this Agreement. The Yukon Property Tax will increase for the additional facilities beyond the aforesaid contemplated capacity in direct proportion to increase in the gross asset value of the Pipeline.

(vii) In the event that between the date of this Agreement and January 1, 1983, the rate of the Alaska property tax on pipelines, taking into account the mill rate and the method of valuation, increases by a percentage greater than the cumulative percentage increase in the Canadian GNP deflator over the same period, there may be an adjustment on January 1, 1983, to the amount of $30 million Canadian described in subparagraph (b)(i) of the Yukon Property Tax to reflect this difference. In defining the Alaska property tax for purposes of this Agreement, the definition of the Yukon Property Tax will apply *mutatis mutandis*.

(viii) In the event that, for any year during the period described in subparagraph (iii), the annual rate of the Alaska property tax on or for the use of the Pipeline in Alaska increases by a percentage over that imposed for the immediate preceding year that is greater than the increase in percentage of the Yukon Property Tax for the year, as adjusted, from that applied to the immediately preceding year, the Yukon Property Tax may be increased to reflect the percentage increase of the Alaska property tax.

(ix) It is understood that indirect socioeconomic costs in the Yukon Territory will not be reflected in the cost-of-service to the United States shippers other than through the Yukon Property Tax. It is further understood that no public authority will require creation of a special fund or funds in connection with construction of the Pipeline in the Yukon, financed in a manner which is reflected in the cost of service to U.S. shippers, other than through the Yukon Property Tax. However, should public authorities in the State of Alaska require creation of a special fund or funds, financed by contributions not fully reimbursable, in connection with construction of the Pipeline in Alaska, the Governments of Canada or the Yukon Territory will have the right to take similar action.

(c) The Government of Canada will use its best endeavors to ensure that the level of any property tax imposed by the Government of the Northwest Territories on or for the use of that part of the Dempster Line that is within the Northwest Territories is reasonably comparable to the level of the property tax imposed by the Government of the Yukon Territory on or for the use of that part of the Dempster Line that is in the Yukon.

6. TARIFFS AND COST ALLOCATION

It is agreed that the following principles will apply for purposes of cost allocation used in determining the cost of service applicable to each shipper on the Pipeline in Canada:

(a) The Pipeline in Canada and the Dempster Line will be divided into zones as set forth in Annex II. Except for fuel and except for Zone 11 (the Dawson-Whitehorse portion of the Dempster Line), the cost of service to each shipper in each zone will be determined on the basis of volumes as set forth in transportation contracts. The volumes used to assign these costs will reflect the original BTU content of Alaskan gas for U.S. shippers and Northern Canadian gas for Canadian shippers, and will make allowance for the change in heat content as the result of commingling. Each shipper will provide volumes for line losses and line pack in proportion to the contracted volumes transported in the zone. Each shipper will provide fuel requirements in relation to the volume of his gas being carried and to the content of the gas as it affects fuel consumption.

(b) It is understood that, to avoid increased construction and operating costs for the transportation of Alaskan gas, the Pipeline will follow a southern route through the Yukon along the Alaska Highway rather than a northern route through Dawson City and along the Klondike Highway. In order to provide alternative benefits for the transportation of Canadian gas to replace those benefits that would have been provided by the northern route through Dawson City, U.S. shippers will participate in the cost of service in Zone 11. It is agreed that if cost overruns on construction of the Pipleline in Canada do not exceed filed costs set forth in Part D of Annex III by more than 35 percent, U.S. shippers will pay the full cost of service in Zone 11. U.S. shipper participation will decline if overruns on the Pipeline in Canada exceed 35 percent; however, at the minimum the U.S. shippers' share will be the greater of either two-thirds of the cost of service or the proportion of contracted Alaska gas in relation to all contracted gas carried in the Pipeline. The proportion of the cost of service borne by U.S. shippers in Zone 11 will be reduced should overruns on the cost of construction in that Zone exceed 35 percent after allowance for the benefits to U.S. shippers derived from Pipeline construction cost savings in other Zones. Notwithstanding the foregoing, at the minimum, the U.S. shippers' share will be the geater of either two-thirds of the cost of service or the proportion of contracted Alaska gas in relation to all contracted gas carried in the Pipeline. Details of this allocation of cost-of-service are set out in Annex III.

(c) Notwithstanding the principles in subparagraphs (a) and (b), in the event that the total volume of gas offered for shipment exceeds the efficient capacity of the Pipeline, the method of cost allocation for the cost of service for shipments of Alaskan gas (minimum entitlement 2.4 bcfd) or Northern Canadian gas (minimum entitlement 1.2 bcfd) in excess of the efficient capacity of the Pipeline will be subject to review and subsequent agreement by both Governments; provided however that shippers of either country may transport additional volumes without such review and agreement, but subject to appropriate regulatory approval, if such transportation does not lead to a higher cost of service or share of Pipeline fuel requirements attributable to shippers of the other country.

(d) It is agreed that Zone 11 costs of service allocated to U.S. shippers will not include costs additional to those attributable to a pipe size of 42 inches. It is understood that in Zones 10 and 11 the Dempster Line will be of the same gauge and diameter and similar in other respects, subject to differences in terrain. Zone 11 costs will include only facilities installed at the date of issuance of the leave to open order, or that are added within three years thereafter.

### 7. SUPPLY OF GOODS AND SERVICES

(a) Having regard to the objectives of this Agreement, each Government will endeavor to ensure that the supply of goods and services to the Pipeline project will be on generally competitive terms. Elements to be taken into account in weighing competitiveness will include price, reliability, servicing capacity and delivery schedules.

(b) It is understood that through the coordination procedures in Paragraph 8 below, either Government may institute consultations with the other in particular cases where it may appear that the objectives of subpargraph (a) are not being met. Remedies to be considered would include the renegotiation of contracts or the reopening of bids.

### 8. COORDINATION AND CONSULTATION

Each Government will designate a senior official for the purpose of carrying on periodic consultations on the implementaton of these principles relating to the construction and operation of the Pipeline. The designated senior officials may, in turn, designate additional representatives to carry out such consultations, which representatives, individually or as a group, may make recommendations with respect to particular disputes or other matters, and may take such other action as may be mutually agreed, for the purpose of facilitating the construction and operation of the Pipeline.

### 9. REGULATORY AUTHORITIES: CONSULTATION

The respective regulatory authorities of the two Governments will consult from time to time on relevant matters arising under this Agreement, particularly on the matters referred to in paragraphs 4, 5 and 6, relating to tariffs for the transportation of gas through the Pipeline.

10. TECHNICAL STUDY GROUP ON PIPE

(a) The Governments will establish a technical study group for the purpose of testing and evaluating 54-inch 1120 pounds per square inch (psi), 48-inch 1260 psi, and 48-inch 1680 psi pipe or any other combination of pressure and diameter which would achieve safety, reliability and economic efficiency for operation of the Pipeline. It is understood that the decision relating to pipeline specifications remains the responsibility of the appropriate regulatory authorities.

(b) It is agreed that the efficient pipe for the volumes contemplated (including reasonable provision for expansion), subject to appropriate regulatory authorization, will be installed from the point of interconnection of the Pipeline with the Dempster Line near Whitehorse to the point near Caroline, Alberta, where the Pipeline bifurcates into a western and an eastern leg.

11. DIRECT CHARGES BY PUBLIC AUTHORITIES

(a) Consultation will take place at the request of either Government to consider direct charges by public authorities imposed on the Pipeline where there is an element of doubt as to whether such charges should be included in the cost of service.

(b) It is understood that the direct charges imposed by public authorities requiring approval by the appropriate regulatory authority for inclusion in the cost of service will be subject to all of the tests required by the appropriate legislation and will include only:

(i) those charges that are considered by the regulatory authority to be just and reasonable on the basis of accepted regulatory practice, and

(ii) those charges of a nature that would normally be paid by a natural gas pipeline in Canada. Examples of such charges are listed in Annex IV.

12. OTHER COSTS

It is understood that there will be no charges on the Pipeline having an effect on the cost of service other than those:

(i) imposed by a public authority as contemplated in this Agreement or in accordance with the Transit Pipeline Treaty, or

(ii) caused by Acts of God, other unforeseen circumstances, or

(iii) normally paid by natural gas pipelines in Canada in accordance with accepted regulatory practice.

13. COMPLIANCE WITH TERMS AND CONDITIONS

The principles applicable directly to the construction, operation and expansion of the Pipeline will be implemented through the imposition by the two Governments of appropriate terms and conditions in the granting of required authorizations. In the event of subsequent non-fulfillment of such a term or condition by an owner of the Pipeline, or by any other private person, the two Governments will not have responsibility therefor, but will take such appropriate action as is required to cause the owner to remedy or mitigate the consequences of such non-fullfillment.

14. LEGISLATION

The two Governments recognize that legislation will be required to implement the provisions of this Agreement. In this regard, they will expeditiously seek all required legislative authority so as to facilitate the timely and efficient construction of the Pipeline and to remove any delays or impediments thereto.

15. ENTRY INTO FORCE

This Agreement will become effective upon signature and shall remain in force for a period of 35 years and thereafter until terminated upon 12 months' notice given in writing by one Government to the other, provided that those provisions of the Agreement requiring legislative action will become effective upon exchange of notification that such legislative action has been completed.

IN WITNESS WHEREOF the undersigned representatives, duly authorized by their respective Governments, have signed this Agreement.

DONE in duplicate at Ottawa in the English and French languages, both versions being equally authentic, this ———— day of ——————, 1977,

| For the Government of the United States: | For the Government of Canada: |
|---|---|
| ———————— | ———————— |

ANNEX I

THE PIPELINE ROUTE

In Alaska:

The Pipeline constructed in Alaska by Alcan will commence at the discharge side of the Prudhoe Bay Field gas plant facilities. It will parallel the Alyeska oil pipeline southward on the North Slope of Alaska, cross the Brooks Range through the Atigun Pass, and continue on to Delta Junction.

At Delta Junction, the Pipeline will diverge from the Alyeska oil pipeline and follow the Alaska Highway and Haines oil products pipeline passing near the towns of Tanacross, Tok, and Northway Junction in Alaska. The Alcan facilities will connect with the proposed new facilities of Foothills Pipe Lines (South Yukon) Ltd. at the Alaska-Yukon border.

In Canada:

In Canada the Pipeline will commence at the Boundary of the State of Alaska, and the Yukon Territory in the vicinity of the towns of Border City, Alaska and Boundary, Yukon. The following describes the general routing of the Pipeline in Canada:

From the Alaska-Yukon border, the Foothills Pipe Lines (South Yukon) Ltd. portion of the Pipeline will proceed in a southerly direction generally along the Alaska Highway to a point near Whitehorse, Yukon, and thence to a point on the Yukon-British Columbia border near Watson Lake, Yukon, where it will join with the Foothills Pipe Lines (North B.C.) Ltd. portion of the Pipeline.

The Foothills Pipe Lines (North B.C.) Ltd. portion of the Pipeline will extend from Watson Lake in a southeasterly direction across the north eastern part of the Province of British Columbia to a point on the boundary between the Provinces of British Columbia and Alberta near Boundary Lake where it will interconnect with the Foothills Pipe Lines (Alta.) Ltd. portion of the Pipeline.

The Foothills Pipe Lines (Alta.) Ltd. portion of the Pipeline will extend from a point on the British Columbia-Alberta boundary near Boundary Lake in a southeasterly direction to Gold Creek and thence parallel to the existing right-of-way of the Alberta Gas Trunk Line Company Limited to James River near Caroline.

From James River a "western leg" will proceed in a southerly direction, generally following the existing right-of-way of the Alberta Gas Trunk Line Company Limited to a point on the Alberta-British Columbia boundary near Coleman in the Crow's Nest Pass area. At or near Coleman the Foothills Pipe Lines (Alta.) Ltd. portion of the Pipeline will interconnect with the Foothills Pipe Lines (South B.C.) Ltd. portion of the Pipeline.

The Foothills Pipe Lines (South B.C.) Ltd. portion of the Pipeline will extend from a point on the Alberta-British Columbia boundary near Coleman in a southwesterly direction across British Columbia generally parallel to the existing pipeline facilities of Alberta Natural Gas Company Ltd. to a point on the International Boundary Line between Canada and the United States of America at or near Kingsgate in the Province of British Columbia where it will interconnect with the facilities of Pacific Gas Transmission Company.

Also, from James River, an "eastern leg" will proceed in a southeasterly direction to a point on the Alberta-Saskatchewan boundary near Empress Alberta where it will interconnect with the Foothills Pipe Lines (Sask.) Ltd. portion of the Pipeline. The Foothills Pipe Lines (Sask.) Ltd. portion of the Pipeline will extend in a southeasterly direction across Saskatchewan to a point on the International Boundary Line between Canada and the United States of America at or near Monchy, Saskatchewan where it will interconnect with the facilities of Northern Border Pipeline Company.

## ANNEX II

### ZONES FOR THE PIPELINES AND THE DEMPSTER LINE IN CANADA

Zone 1: *Foothills Pipe Lines (South Yukon) Ltd.*—Alaska Boundary to point of interconnection with the Dempster Line at or near Whitehorse.

Zone 2: *Foothills Pipe Lines (South Yukon) Ltd.*—Whitehorse to Watson Lake.

Zone 3: *Foothills Pipe Lines (North B.C.) Ltd.*—Watson Lake to point of interconnection with Westcoast's main pipeline near Fort Nelson.

Zone 4: *Foothills Pipe Lines (North B.C) Ltd.*—Point of interconnection with Westcoast's main pipeline near Fort Nelson to the Alberta-B.C. border.

Zone 5: *Foothills Pipe Lines (Alta.) Ltd.*—Alberta-B.C. border to point of bifurcation near Caroline, Alberta.

Zone 6: *Foothills Pipe Lines (Alta.) Ltd.*—Caroline, Alta. to Alberta-Saskatchewan border near Empress.

Zone 7: *Foothills Pipe Lines (Alta) Ltd.*—Caroline to Alberta-B.C. border near Coleman.

Zone 8: *Foothills Pipe Lines (South B.C.) Ltd.*—Alberta-B.C. border near Coleman to B.C.-U.S. border near Kingsgate.

Zone 9: *Foothills Pipe Lines (Sask.) Ltd.*—Alberta-Saskatchewan border near Empress to Saskatchewan-U.S. border near Monchy.

Zone 10: *Foothills Pipe Lines (North Yukon) Ltd.*—Mackenzie Delta Gas fields in the Mackenzie Delta, N.W.T., to a point near the junction of the Klondike and Dempster highways just west of Dawson, Yukon Territory.

Zone 11: *Foothills Pipe Lines (South Yukon) Ltd.*—A point near the junction of the Klondike and Dempster highways near Dawson to the connecting point with the Pipeline at or near Whitehorse.

## ANNEX III

### COST ALLOCATION IN ZONE 11

The cost of service in Zone 11 shall be allocated to United States shippers on the following basis:

(i) There will be calculated, in accordance with (iii) below, a percentage for Zones 1–9 in total by dividing the actual capital costs by the filed capital costs and multiplying by 100. If actual capital costs are equal to or less than 135% of filed capital costs, then United States shippers will pay 100% of the cost of service in Zone 11. If actual capital costs in Zones 1–9 are between 135% and 145% of filed capital costs, then the percentage paid by United States shippers will be adjusted between 100% and 66⅔% on a straight-line basis, except that in no case will the portion of cost of service paid by United States shippers be less than the proportion of the contracted volumes of Alaskan gas at the Alaska-Yukon border to the same volume of Alaskan gas plus the contracted volume of Northern Canadian gas. If the actual capital costs are equal to or exceed 145% of filed capital costs, the portion of the cost of service paid by United States shippers will be not less than 66⅔% or the proportion as calculated above, whichever is the greater.

(ii) There will be calculated a percentage for the cost-overrun on the Dawson to Whitehorse lateral (Zone 11). After determining the dollar value of the overrun, there will be deducted from it:

(a) the dollar amount by which actual capital costs in zones 1, 7, 8 and 9 (carrying U.S. gas only) are less than 135% of filed capital costs referred to in (iii) below;

(b) in each of Zones 2, 3, 4, 5 and 6 the dollar amount by which actual capital costs are less than 135% of filed capital costs referred to in (iii) below, multiplied by the proportion that the U.S. contracted volume bears to the total contracted volume in that zone.

If the actual capital costs in Zone 11, after making this adjustment, are equal to or less than 135% of filed capital costs, then no adjustment is required to the percentage of the cost of service paid by United States shippers as calculated in (i) above. If, however, after making this adjustment, the actual capital cost in Zone 11 is greater than 135% of the filed capital cost, then the proportion of the cost of service paid by United States shippers will be a fraction (not exceeding 1) of the percentage of the cost of service calculated in (i) above, where the numerator of the fraction is 135% of the filed capital cost and the denominator of the fraction is actual capital cost less the adjustments from (a) and (b) above. Notwithstanding the adjustments outlined above, in no case will the percentage of the actual cost of service borne by United States shippers be less than the greater of 66⅔% or the proportion of the contracted volumes of Alaskan gas at the Alaska-Yukon border to the same volume of Alaskan gas plus the contracted volume of Northern Canadian gas.

(iii) The "filed capital cost" to be applied to determine cost overruns for the purpose of cost allocation in (i) and (ii) above will be:

*"Filed Capital Cost" Estimates for the Pipeline in Canada*

[millions of canadian dollars]

| | |
|---|---|
| The Pipeline in Canada (Zones 1–9):[1] | |
| 48"—1,260 lb. pressure pipeline | 3,873 |
| or 48"—1,680 lb. pressure pipeline | 4,418 |
| or 54"—1,120 lb. pressure pipeline | 4,234 |

[1] These filed capital costs include and are based upon (a) a 1,260 psi, 48-inch line from the Alaska-Yukon border to the point of possible interconnection near Whitehorse; (b) a 1,260 psi, 48-inch; or 1,680 psi, 48-inch; or 1,120 psi 54-inch line from the point of possible interconnection near Whitehorse to Caroline Junction; (c) a 42-inch line from Caroline Junction to the Canada-U.S. border near Monchy, Saskatchewan; and (d) a 36-inch line from Caroline Junction to the Canada-U.S. border near Kingsgate, British Columbia. These costs are escalated for a date of commencement of operations of January 1, 1983.

*"Filed Capital Cost" Estimates for the Pipeline in Canada*

[millions of canadian dollars]

| | |
|---|---|
| Zone 11 of the Dempster line:[2] | |
| 30"—Section of Dempster line from Whitehorse to Dawson | 549 |
| or 36"—Section of Dempster line from Whitehorse to Dawson | 585 |
| or 42"—Section of Dempster line from Whitehorse to Dawson | 705 |

[2] The costs are escalated for a date of commencement of operations of January 1, 1985.

Details for Zones 1–9 are shown in the following table:

FILED CAPITAL COSTS FOR THE PIPELINE IN CANADA

[In millions of Canadian dollars]

| Zone | 48" 1,260 psi | 48" 1,680 psi | 54" 1,120 psi |
|---|---|---|---|
| 1 | 707 | 707 | 707 |
| 2 | 721 | 864 | 805 |
| 3 | 738 | 850 | 803 |

FILED CAPITAL COSTS FOR THE PIPELINE IN CANADA—Continued

[In millions of Canadian dollars]

| Zone | 48" 1,260 psi | 48" 1,680 psi | 54" 1,120 psi |
|---|---|---|---|
| 4 | 380 | 488 | 456 |
| 5 | 677 | 859 | 813 |
| 6 | 236 | 236 | 236 |
| 7 | 126 | 126 | 126 |
| 8 | 83 | 83 | 83 |
| 9[1] | 205 | 205 | 205 |
| Total, zones, 1 to 9 | 3,873 | 4,418 | 4,234 |

[1] The last compression station in Zone 9 includes facilities to provide compression up to 1,440 psi.

It is recognized that the above are estimates of capital costs. They do not include working capital, property taxes or the provision for road maintenance in the Yukon Territory (not to exceed $30 million Canadian).

If at the time construction is authorized, both Governments have agreed to a starting date for the operation of the Pipeline different from January 1, 1983, then the capital cost estimates shall be adjusted for the difference in time using the GNP price deflator from January 1, 1983. Similarly at the time construction is authorized for the Dempster Line, if the starting date for the operation agreed to by the Canadian Government is different from January 1, 1985, then the capital cost estimate shall be adjusted for the difference in timing using the GNP price deflator from January 1, 1985. The diameter of the pipeline in Zone 11, for purposes of cost allocation, may be 30", 36" or 42", so long as the same diameter pipe is used from the Delta to Dawson (Zone 10).

The actual capital cost, for purposes of this Annex will be the booked cost as of the date "leave to open" is granted plus amounts still outstanding to be accrued on a basis to be approved by the National Energy Board. Actual capital costs will exclude working capital, property taxes, and direct charges for road maintenance of up to $30 million Canadian in the Yukon Territory as specifically provided herein.

For purposes of this Annex above, actual capital costs wil exclude the effect of increases in cost or delays caused by actions attributable to the U.S. shippers, related U.S. pipeline companies, Alaskan producers, the Prudhoe Bay deliverability or gas conditioning plant construction and the United States or State Governments. If the appropriate regulatory bodies of the two countries are unable to agree upon the amount of such costs to be excluded, the determination shall be made in accordance with the procedures set forth in Article IX of the Transit Pipeline Treaty.

The filed capital costs of facilities in Zones 7 and 8 will be included in calculations pursuant to this Annex only to the extent that such Facilities are constructed to meet the requirements of U.S. shippers.

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## ANNEX IV

### DIRECT CHARGES BY PUBLIC AUTHORITIES

*1. Crossing damages (roads, railroad crossings, etc.; this item is usually covered in the crossing permit).

*2. Road damages caused by exceeding design load limits.

*3. Required bridge reinforcements caused by exceeding design load limits.

4. Airfield and airstrip repairs.
5. Drainage maintenance.
6. Erosion control.
7. Borrow pit reclamation.
8. Powerline damage.
9. Legal liability for fire damage.
10. Utility system repair (water, sewer, etc.).
11. Camp waste disposal.
12. Camp site reclamation.
13. Other items specified in environmental stipulations.
14. Costs of surveillance and related studies as required by regulatory bodies or applicable laws.

## ANNEX V

British Columbia statement

The Government of the Province of British Columbia agrees in principle to the provisions contained in the Canada-United States Pipeline Treaty of January 28, 1977, and furthermore British Columbia is prepared to cooperate with the Federal Government to ensure that the provisions of the Canada-United States Treaty, with respect to non-interference of throughput and non-discriminatory treatment with respect to taxes, fees or other monetary charges on either the pipeline or throughput, are adhered to. Specific details of this undertaking will be the subject of a Federal-Provincial Agreement to be negotiated at as early a date as possible. Such Agreements should guarantee that British Columbia's position expressed in its telegram of August 31 is protected.

Alberta statement

The Government of the Province of Alberta agrees in principle to the provisions contained in the Canada-United States Pipeline Treaty of January 28, 1977, and furthermore, Alberta is prepared to cooperate with the Federal Government to ensure that the provisions of the Canada-United States Treaty, with respect to non-interference of throughput and non-discriminatory treatment with respect to taxes, fees, or other monetary charges on either the Pipeline or throughput, are adhered to. Specific details of this undertaking will be the subject of a Federal-Provincial Agreement to be negotiated when the Canada-United States protocol or understanding has been finalized.

*In the case of these items and all other road related charges by public authorities, total charges in the Yukon Territory shall not exceed Canadian $30 million.

Saskatchewan statement

The Government of Saskatchewan is willing to cooperate with the Government of Canada to facilitate construction of the Alcan Pipeline through southwestern Saskatchewan and, to that end, the Government of Saskatchewan expresses its concurrence with the principles elaborated in the Transit Pipeline Agreement signed between Canada and the United States on January 28, 1977. In so doing, it intends not to take any discriminatory action towards such pipelines in respect of throughput, reporting requirements, and environmental protection, pipeline safety, taxes, fees or monetary charges that it would not take against any similar pipeline passing through its jurisdiction. Further details relating to Canada-Saskatchewan relations regarding the Alcan Pipeline will be the subject of Federal-Provincial agreements to be negotiated after a Canada-United States understanding has been finalized.

## REPORT ACCOMPANYING A DECISION ON AN ALASKA NATURAL GAS TRANSPORTATION SYSTEM

### PREFACE

The Alaska Natural Gas Transportation Act (ANGTA) established a unique and comprehensive process designed to make use of the collective expertise of various branches and departments of government in reaching a final decision on an Alaska Natural Gas Transportation System. By statutory direction, after months of hearings, the Federal Power Commission issued on May 1, 1977, a one-volume report, *Recommendation to the President,* which urged the designation of an overland pipeline system. After the FPC Report, pursuant to Section 6(a) of ANGTA, ten Federal interagency task forces were organized to report, not later than July 1, 1977, on the impacts and considerations of an Alaska natural gas transportation system. The July 1 Reports submitted by these task forces covered the following subjects:

1. The energy policy impacts of an Alaska natural gas project;
2. Environmental considerations;
3. Sources of financing for capital costs;
4. The impact on competition;
5. Safety and design;
6. International relations;
7. National security, particularly security of supply;
8. Impact on the national economy;
9. Potential cost overruns and time delay; and
10. Socioeconomic impact of the transportation system.

Pursuant to Section 6(d) of ANGTA, the Council of Environmental Quality submitted a report on July 1, 1977, which found that the environmental impact statements submitted by the FPC with respect to Alcan, pursuant to Section 5(e) of ANGTA, are legally and factually sufficient.

In the preparation of this decision, all the interagency reports, the FPC *Recommendation,* and many other submissions and public comments received from Governors, local officials and other interested individuals have been carefully considered. This Report to the Congress on an Alaska Natural Gas Transportation System, as well as the President's decision which precedes it, are the product of this collective study process. As required by the Alaska Natural Gas Transportation Act, this Report explains in detail the basis for the decision favoring the Alcan project.

## Chapter I—Desirability of an Alaska Natural Gas Project

### NATURAL GAS SUPPLY

United States

There is currently estimated to be a potential natural gas demand in the United States of 25 to 30 trillion cubic feet per year. The U.S. will have to use every source it can to maintain the early 1970 production level of approximately 20 trillion cubic feet per year. As our dependence on foreign sources of energy continues to rise, the nation can use all the reasonably priced domestic natural gas it can produce to displace oil imports. Because of its premium nature, the more gas the U.S. produces, the more it will be able to use.

Looking toward 1990, even under the most optimistic conservation and production assumptions, natural gas shortages are a very real possibility, even with the delivery of Alaska gas. This is so because of the expected tapering off of domestic gas production in the lower-48 states, and a reversal in the decline of natural gas demand when conservation measures have had their full effect and the nation experiences a renewed increase of demand growth from normal economic activity. This situation could be further aggrevated by the expiration and nonrenewal of Canadian gas export contracts through the 1980's. The Alcan project maximizes our chances for avoiding such curtailments.

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.

Additionally, such projections do not make any allowance for unusually cold weather, such as that experienced last winter. The increase in gas demand last winter for space heating in the residential sector alone was estimated to be over 0.4 tcf. Under these probabilities, gas shortages are likely in the near future and throughout the 1980's with or without substantial new sources of supply.

In general, there are three economically attractive means to supplement traditional domestic gas supplies by 1985. The first is to accelerate OCS leasing in the Gulf of Mexico, which could produce as much as an additional 0.2 tcf per year by 1985 and 0.6 tcf per year by 1990. The second is to import gas from Mexico, which could be as much as 0.5 tcf per year by 1985 and 0.7 tcf per year by 1990 if the recently-announced gas sales contracts should be completed and approved. The third is to proceed with an Alaska gas project.

Proved saleable gas reserves of 20.6 to 22.8 trillion cubic feet (tcf) in the Main Pool accumulation in the Prudhoe Bay Field represent more than a full year of natural gas consumption at the current consumption rate of about 17.3 tcf per year. Prudhoe Bay production at 2.4 bcfd of gas will include production from other reservoirs which have been identified in the field, the Kuparuk and the Lisburne. Production at that rate would increase domestic gas production by approximately 5 percent in the years when Alaska gas first becomes available. Additional gas discoveries on the North Slope, or in other areas of Alaska through which the pipeline passes, would increase potential deliverability even further.

The certain increase in supply from an Alaska gas project is estimated to be 0.7 tcf per year (2.0 bcfd) by 1985. By 1990, a volume greater than 0.9 tcf per year (2.4 bcfd) might be produced.

Under the best of circumstances—which assume the most optimistic supply projections, demand reductions and fuel substitutions—the addition of Alaska gas to domestic production will make a substantial contribution toward closing the gap between natural gas supply and demand. Such additional gas supplies could allow some industries with special processes to continue burning natural gas longer, and allow more residential use of natural gas, further displacing oil imports.

By 1990, use of every conceivable supply option under any scenario may still leave us with serious domestic gas shortages. By 1990, oil imports are projected to be 9.6 mmbd, provided that supplemental supply sources can furnish gas in the following volumes:

0.9 tcf per year from Alaska gas;

0.7 tcf per year from Mexican gas exports;

0.6 tcf per year from accelerated OCS leasing in the Gulf of Mexico.

Clearly, each of these gas supply options will become more desirable and important as conventional gas supplies decline in the years after 1990.

Our best efforts will only temporarily stem the decline in conventional onshore gas production in the lower-48 states. The U.S. may increasingly need supplemental sources of gas supply to meet demand. These will include:

Geopressurized methane;
Devonian shale;
Deeper, tighter, formations;
Coal gasification;
Imports of liquefied natural gas (LNG);
Synthetic natural gas (SNG).

Although Alaska gas will add about 5 percent to total domestic gas production, it will be a larger proportion of supply for consumers in the Middle West and on the West Coast. For these regions, it will be between 6 and 10 percent of their supply depending on the distribution which is reflected in the final gas sales contracts. These volumes will be important to the availability of gas in these regions, and should be delivered at a competitive price with other supplemental sources of supply.

Canada

One of the most significant effects of the Alcan project on gas supply will be its effect on Canada's natural gas sales policies. In its July 4th decision on a northern pipeline project, the Canadian National Energy Board (NEB) found that unless the project gave Canadians access to their frontier gas reserves, Canada might not have sufficient supplies available to fulfill its existing gas export commitments to the U.S. If the frontier gas reserves were made available, however, increased supplies would exist to allow continuation of current export levels.

A possibility offered by the Alcan project is the effective availability of Alaska gas to the U.S. before completion of the project through pre-delivery of Canadian gas under existing export licenses. 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 commitments in the late 1980's, or by time-swaps for Alaska gas. The pre-deliveries 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.

A pre-delivery arrangement involving Alberta gas would provide stimulus to exploration for additional supplies in that province by providing producers with additional markets for their gas. Similarly, agreement on a project which brings a major pipeline effectively within 500 miles of the Mackenzie Delta region should stimulate further exploration activity there. If that additional exploration is undertaken, the possibility of obtaining additional volumes of Canadian gas in future years will be enhanced. The joint project will thus ensure maximum availability of Canadian gas in the near term, through continued exports under existing contracts and possible pre-deliveries. It will also give the U.S. its best chance of obtaining longer-term supplies of Canadian gas by providing the impetus for broad-scale exploration programs.

## ECONOMIC CONSIDERATIONS

An economic analysis of the Alaska gas projects can be made from both a private market perspective and from a national economic perspective. The utility of the project from a private market perspective is determined by whether there are less expensive alternative fuels available. This depends on the field price of the gas and the transportation cost. The reliance upon the National Energy Plan (NEP) for setting of a field price is discussed in Section 6 of the *Decision*. For illustrative purposes here, the $1.45 price that would be set under the NEP is used. The transportation cost of service will be determined by the capital and operating costs of the delivery system. The project applicants have filed cost estimates that produce a 20-year average cost of service which ranges from $.80 to $1.07 per mmbtu (1975 dollars).

The large cost overruns of the Alyeska pipeline have raised new concerns regarding the accuracy of base capital cost estimates for such major projects. For the Alaska gas project, cost overrun assessments have been made which allow for capital cost increases by factors from about 1.3 to 2.0.

The expected 20-year average cost of service for the Alcan project described in the *Decision*, and including an expected case 40 percent cost overrun, is estimated at approximately $1.04 per mmbtu in constant 1975 dollars. The cost of service under similar assumptions for the EL Paso project is $1.21 per mmbtu. The "worst case" estimates for both projects result in a 20-year average cost of service of about $1.80 to $2.00 per mmbtu. In addition, the transporters (i.e., the project sponsors) will probably be required to bear a portion of the "conditioning" or processing cost of the gas. When the cost of service price of the Alcan project is added to a wellhead price of $1.45 to $1.75 per mmbtu (depending on the amount the FPC will allow producers for their processing costs), the wholesale or "city gate" price of the gas should be about $2.50 to $2.80 per mmbtu in constant 1975 dollars. The delivered cost of Alcan gas under three different overrun assumptions is:

20-YEAR AVERAGE ALCAN DELIVERED COST

[1975 dollars]

| | Filed costs | Expected cost overrun | Worst case cost overrun |
|---|---|---|---|
| Field price | $1.45 | $1.45 | $1.45 |
| Processing | 0 to 0.30 | 0 to 0.30 | 0 to 0.30 |
| Transportation | 0.80 | 1.04 | 1.57 |
| Total | 2.25 to 2.55 | 2.49 to 2.79 | 3.02 to 3.32 |

The conservatively projected costs of imported LNG and other alternative non-conventional gas supplies would be at least $3.25 per mmbtu (in 1975 dollars). SNG would be at least $3.75 per mmbtu. Only if there were a "worst case" cost overrun and high processing costs would Alaska gas be more expensive than imported LNG; it would still be considerably less expensive than SNG. One of the most important objectives of the Federal Government's involvement during the planning and construction period will be to avoid such "worst case" overruns.

Estimates of availability and cost of gas from coal gasification and other unconventional sources must be considered speculative at this time. However, as there are no confirmed estimates which put the city gate price of marketable amounts of gas from these sources below $3.50 to $4.00 per mmbtu, the Alcan project would appear to be competitive for the life of the project.

The measure of the project's value to the nation is the Net National Economic Benefit (NNEB), which compares the present value of real resource expenditures for the project with the present value of its future benefits. The resource expenditures are measured by the capital and operating expenses. The benefits are measured by the costs of alternate fuel displaced by the gas, such as imported oil or LNG. The benefit value which has been used for evaluating this project is approximately $2.60 per mmbtu (1975 dollars). This analysis shows that both the El Paso and Alcan projects would have net benefits of almost $5.0 billion at the expected overrun cost. This clearly indicates that construction of some project is preferable to the no project option. Significantly, the benefits of either project remain positive, although smaller, at the "worst case" cost overrun level. Most significantly, the NNEB of the Alcan project is over $1.1 billion more than that of El Paso under the expected overrun case as indicated below:

[In billions of dollars]

| | "Expected" costs | "Worst case" costs |
|---|---|---|
| Alcan project | 5.7 | 1.8 |
| El Paso | 4.6 | .7 |

If the resource value assumption is changed to take account of the reasonable potential for an increasing world oil price over the 25-year accounting life of the project, or if the price of supplemental gas supplies such as SNG (now at $3.75 or more per mmbtu) is used, and if the benefits of the project beyond its 25-year accounting life are included, the expected case NNEB more than doubles.

### CONCLUSION

This analysis indicates the importance and superiority of the Alcan project as compared to either the El Paso project or the no project option. It appears that Alaska gas will be one of our cheapest sources of supplemental gas supply and will assure at least near-term continuation of our access to Canadian gas supplies.

Even if we achieve the ambitious coal conversion, conservation and production goals outlined in the National Energy Plan, Alaska gas provides us with a needed additional resource for helping reduce oil imports while heating more of our homes and running more of our factories with a premium domestically produced fuel. If we fall short of our goals, Alaskan gas is essential in the effort to minimize imports and help fill the gap between natural gas supply and demand.

A realistic assessment of all the supply and demand potentials indicates that Alaska gas delivered by the Alcan system will be an important source of energy. The Alcan project has a high expected net national economic benefit. It should provide transportation services at a projected cost that will assure the sale of Alaska gas. The Alcan project is both a good investment for the United States as a matter of national energy policy, and a good investment for the private interests that will manage and finance its construction.

## CHAPTER II—FINANCIAL ANALYSIS

### CONCLUSIONS

As indicated by the terms and conditions in Section 5 of the *Decision*, the Alcan project is required to be privately financed. As such, it will be the largest privately financed energy project ever undertaken, requiring between $10 billion and $15 billion by the time it is completed. This Chapter addresses the reasons for concluding the project can be privately financed and the conditions under which a private financing is expected to occur.

To effectuate such a private financing, a plan that equitably and carefully balances the project's benefits and risks is required. The following plan to share the risks and benefits of the Alcan project is proposed:

1. The equity investment in the project would be placed at risk under all circumstances and the budgeted equity investment be considered the first funds spent. The rate of return on equity would compensate sponsors for bearing this risk.

2. Producers and the State of Alaska, as direct and major beneficiaries of this project, should participate in the financing either directly or in the form of debt guarantees.

3. The burden of cost overruns be shared by equity holders and consumers upon completion through the application of a variable rate of return on common equity. This would provide a strong incentive for the project to be constructed at the lowest possible cost.

4. Provision of debt service in the event of service interruption would be borne by consumers through a tariff that becomes effective only after service commences.

ANALYSIS

Given the large volumes of proven reserves in the Prudhoe Bay Oil Pool, the high degree of experience and excellent performance record of gas pipeline transmission facilities, the support and best efforts of Canada, and the clear need for additional natural gas supplies throughout the United States, there is good reason to expect this project will be financed by the capital markets without the use of consumer noncompletion agreements. This determination takes into account the following considerations:

1. The risks associated with the construction and operation of the Alcan project must be assumed by creditworthy parties in order to achieve private financing. There is sufficient credit support capacity among the direct beneficiaries of the project to assure completion of the pipeline without assistance from consumers. Such beneficiaries are the gas transmission companies, gas producers, and the State of Alaska. The benefits of these parties sufficiently outweigh the risks associated with the project so that it is reasonable to expect them to provide support at small additional cost to consumers. Once operation begins, however, consumers must expect to pay the full cost of service based upon certified expenditures.

2. To reduce uncertainty to a minimum, the Federal Government should:

(a) Specify clearly the terms and conditions that are to be imposed on the pipeline during its construction and operation prior to commencement of construction;

(b) Provide a mechanism to coordinate engineering and environmental regulation and permit rapid and unambiguous resolution of any difficulties which may be encountered;

(c) Provide for timely approval of outlays for incorporation into the project's rate base;

(d) Provide a mechanism to permit a high degree of cooperation with Canada and rapid resolution of any difficulties which are encountered;

(e) Allow sufficient time to plan, coordinate and manage procurement, logistics and construction.

3. To hold the total direct cost of the project to a minimum and the project on schedule, it is desirable to:

(a) Develop a variable rate of return on equity that provides for a realizable high return if actual costs are near or below budget and a reduced return if cost overruns occur;

(b) Provide for similar treatment of the return on equity in both the U.S. and Canada;

(c) Provide an incentive to the Canadian Government and its regulatory authorities to achieve all possible cost savings and promote management efficiency.

The Terms and Conditions in Section 5 of the *Decision*, along with the Agreement on Principles included as Section 7, provides the requisite processes and assurances for the reduction of both uncertainty and costs.

The conclusion reached here regarding private financing without consumer noncompletion guarantees differs substantially from the position taken by most parties in the Federal Power Commission proceeding and by representatives of El Paso in their most recent statements. These statements were made prior to the significant steps that have been taken in recent weeks to reduce uncertainty and create proper planning, control and incentives. While the fundamental economic potential of the project has not changed, the likelihood of achieving that potential is greater.

## ALCAN FINANCIAL PLAN

The Alaska natural gas transportation project proposed by Alcan will involve a large and complex financing which will be arranged prior to the commencement of construction.[1] In view of the size of the project relative to the financing capacity of its sponsors, Alcan has proposed that the required capital be raised and secured by means of "project financing" as distinguished from the more traditional "balance sheet financing" used in the gas pipeline industry. That is, a new project entity will be created which will be expected in and of itself to generate sufficient revenues to pay for its operating costs, interest and principal on debt, and a return on, and ultimately a return of, equity to its investors.

It is expected that the equity funds for the project entities will be provided by the sponsoring consortium companies.[2] Debt capital will come from a variety of lenders.

The basic requirement for a successful financing is the economic viability of the project. In Chapter IV of the *Report*, the basic economic soundness of the project is demonstrated. Even under extreme cost overruns, the delivered cost of Alaska gas will be economically attractive. Appropriate incentives will encourage the

[1] A detailed financial analysis of the competing proposals can be found in *Report to the President, Financing an Alaskan Gas Transportation System*, Department of the Treasury, Lead Agency, and other participating Agencies: July 1, 1977.

[2] For the sake of simplicity, the new interdependent project entities will hereafter be referred to collectively as "the project."

minimization of cost overruns. Pipeline and gas distribution companies can be expected to purchase the Alaska gas from Prudhoe Bay producers under long-term contracts and sign transportation contracts with Alcan.

The conclusion that Alcan can be privately financed is founded on the basis economic desirability of Alaska gas and the viability Alcan transportation system; nevertheless, skillful financial packaging and risk-benefit balancing will be required. It is therefore necessary to explore the boundaries of the financing problem by considering Alcan's likely capital needs and sources, relating those needs to the capital market in general, and reviewing the list of beneficiaries and examining the roles each might be expected to play in the financing.

Capital requirements and sources of funds

Alcan has estimated the capital costs of its system under varying design, route and completion date assumptions. It has also made two capital requirements and source of funds projections under its 48-inch proposal: one was filed with the FPC in March 1977, and was based upon an "Express" 1260 psi line carrying no Canadian gas; the other was based upon the July 4, 1977, NEB-recommended modifications of that system to divert to Dawson in order to carry Canadian gas and make $200 million in socio-economic payments. Both of these projections assumed delivery beginning October 1, 1981.

The Agreement on Principles with Canada has altered the system from that specified by the NEB. This alteration has little affect on the basic total capital needs of the system as compared with the needs estimated for the system incuding the NEB recommendations; the capital saved by rerouting from the Dawson diversion back to the prime route is almost exactly offset by the additional cost of installing a higher-capacity pipeline system from Whitehorse to Caroline Junction.[3] Thus by simply adjusting the Alcan financial plan for the NEB recommended system to reflect a more realistic commencement date of January 1, 1983, a financial plan consistent with the agreed-upon system design, route and commencement date results. Exhibits 1 and 2 display the original and adjusted Alcan plans.

Alcan is expected to require approximately $10.3 billion according to cost estimates filed with U.S. and Canadian regulatory bodies, adjusted to reflect commencement of operations on January 1, 1983. The projected sources for these funds are the following:

| | Millions |
|---|---|
| U.S. banks | $1,233 |
| Canadian banks | 542 |
| U.S. long-term debt | 5,865 |
| Canadian long-term debt | 445 |
| U.S. common stock | 1,362 |
| Canadian common stock | 855 |
| Total | 10,302 |

[3] On the basis of filed costs, moving back to the prime route saves $444 million while putting in 1680 psi pipe adds $472 million. The overrun estimate was $630 million for the Dawson diversion and $565 million for the increase in the capacity of the system

With cost overruns, the requirements would be higher. For example, if the projected cost overrun percentage detailed elsewhere in this report of approximately 32 percent is used, the total capital requirements would rise to approximately $13.6 billion.

## Capital markets

The capital requirements of the Alcan project are so large that the project cannot be viewed in conventional terms by its pipeline sponsors and other potential investors. At the end of 1976, the total assets of the gas transmission industry were $26 billion. The project must be seen as a corporate entity in itself, capable of issuing and servicing its own debt and equity.

EXHIBIT 1.—FINANCING REQUIREMENTS OF COMPANIES ASSOCIATED WITH THE ALCAN PIPELINE PROJECT[1] (1978–82)

[In millions of dollars]

| | 1978 | 1979 | 1980 | 1981 | 1982 | Total basic requirements |
|---|---|---|---|---|---|---|
| Alcan Pipeline: | | | | | | |
| U.S. banks | | 36 | 555 | 279 | | 870 |
| U.S. long-term debt | | 700 | 600 | 450 | | 1,750 |
| U.S. common stock | | 350 | 270 | 260 | | 880 |
| Total Alcan Pipeline | | 1,086 | 1,425 | 989 | | 3,500 |
| Foothills Group: | | | | | | |
| Canadian banks | | 110 | 300 | 100 | | 510 |
| U.S. long-term debt | | 321 | 1,038 | 736 | | 2,095 |
| Canadian long-term debt | 75 | 100 | 100 | | 144 | 419 |
| Canadian common stock | 220 | 172 | 256 | 149 | 7 | 804 |
| Total Foothills Group | 295 | 703 | 1,694 | 985 | 151 | 3,828 |
| PG&E: | | | | | | |
| U.S. banks | | | | | | |
| U.S. long-term debt | | | | 388 | | 388 |
| U.S. common stock | | | | | | |
| Total PG&E | | | | 388 | | 388 |
| PG&E: | | | | | | |
| U.S. banks | | | | | | |
| U.S. long-term debt | | 82 | 205 | 77 | | 364 |
| U.S. common stock | | | | | | |
| Total PG&E | | 82 | 205 | 77 | | 364 |
| Northern Border: | | | | | | |
| U.S. banks | | | | 290 | | 290 |
| U.S. long-term debt | | 46 | 410 | 465 | | 921 |
| U.S. common stock | | 16 | 136 | 250 | | 402 |
| Total Northern Border | | 62 | 546 | 1,005 | | 1,613 |
| Total: | | | | | | |
| Canadian funds | 295 | 382 | 656 | 249 | 151 | 1,733 |
| U.S. funds | | 1,551 | 3,214 | 3,195 | | 7,960 |
| | 295 | 1,933 | 3,870 | 3,444 | 151 | 9,693 |

[1] Assumes "Dawson Re-Routing" and Oct. 1, 1981, gas deliveries.
Source: Documents Submitted by Alcan Project to White House Task Force, Aug. 2, 1977, tab 4, schedule B.

EXHIBIT 2.—ADJUSTED FINANCING REQUIREMENTS OF COMPANIES ASSOCIATED WITH THE ALCAN PIPELINE PROJECT[1] (1979–83)

[In millions of dollars]

| | 1979 | 1980 | 1981 | 1982 | 1983 | Total basic requirements |
|---|---|---|---|---|---|---|
| Alcan Pipeline: | | | | | | |
| U.S. banks | | 38 | 590 | 297 | | 925 |
| U.S. long-term debt | | 744 | 638 | 478 | | 1,860 |
| U.S. common stock | | 372 | 287 | 276 | | 935 |
| Total Alcan Pipeline | | 1,154 | 1,515 | 1,051 | | 3,720 |
| Foothills Group: | | | | | | |
| Canadian banks | | 117 | 319 | 106 | | 542 |
| U.S. long-term debt | | 341 | 1,103 | 782 | | 2,227 |
| Canadian long-term debt | 80 | 106 | 106 | | 153 | 445 |
| Canadian common stock | 234 | 183 | 272 | 158 | 7 | 855 |
| Total Foothills Group | 314 | 747 | 1,800 | 1,046 | 160 | 4,069 |
| PG&E: | | | | | | |
| U.S. banks | | | | | | |
| U.S. long-term debt | | | | 412 | | 412 |
| U.S. common stock | | | | | | |
| Total PG&E | | | | 412 | | 412 |
| PG&E: | | | | | | |
| U.S. banks | | | | | | |
| U.S. long-term debt | | 87 | 218 | 82 | | 387 |
| U.S. common stock | | | | | | |
| Total PG&E | | 87 | 218 | 82 | | 387 |
| Northern Border: | | | | | | |
| U.S. banks | | | | 308 | | 308 |
| U.S. long-term debt | | 49 | 436 | 494 | | 979 |
| U.S. common stock | | 17 | 145 | 266 | | 427 |
| Total Northern Border | | 68 | 581 | 1,068 | | 1,714 |
| Total: | | | | | | |
| Canadian funds | 314 | 406 | 697 | 265 | 160 | 1,842 |
| U.S. funds | | 1,649 | 3,416 | 3,396 | | 8,460 |
| | 314 | 2,055 | 4,113 | 3,661 | 160 | 10,302 |

[1] Based upon financial plan presented to White House Staff on Aug. 2, 1977, adjusted to reflect 1¼-year lag in outlays and 5 percent inflation factor.

While this investment is large for the industry, its importance in terms of aggregate investment or total capital markets is modest. To put these requirements into perspective, U.S. gross private investment in 1976 was $241 billion. Alcan's peak year capital needs for U.S. funds, expressed in 1976 dollars, are only 1.1 percent of total U.S. gross private investment for that year, which was not a particularly good one for the economy.

It is anticipated that most if not all, of the U.S. common equity will come from U.S. shippers (i.e., U.S. transmission or distribution companies). A broad consortium of companies would have sufficient financial capacity to make the required $1.4 billion investment. The transmission sector of the industry alone had almost double that amount in annual cash flow in 1976. While the industry must continue to make other investments, its internal cash flow, plus the ability to issue new securities, provides ample capacity to fund the necessary equity investment, including the equity portion of potential cost overruns.

The Canadian equity is expected to be provided by the four companies supporting the project in Canada: Westcoast Transmission Company, Ltd., Alberta Gas Trunkline Company, Ltd. (AGTL), Alberta Natural Gas Company, Ltd., and Trans-Canada Pipelines, Ltd. While the first two companies are the major and previously the only firms in the Canadian consortium, the addition of the latter two in recent weeks has contributed additional financial strength to the Alcan project.[4]

As to the debt portion of financing this project, Alcan's impact on the U.S. debt market cannot be considered burdensome. In 1976, non-government long-term debt offerings in the U.S. totaled $62.9 billion. Ignoring the state of the economy in 1976 and not including the likely positive real growth of the long-term debt market from 1976 until the Alcan debt is issued, Alcan's projected total U.S. long-term debt requirement (including the Foothills Group debt sold in the U.S.) in its peak year is only 3 percent of the market (both expressed in 1976 dollars). Over the five-year period, 1978 through 1982, the aggregate requirement is less than approximately 1.4 percent.

Similarly, the Canadian long-term debt to be issued by the Foothills group expressed as a fraction of all corporate bonds issued in Canada in 1975 is approximately 5 percent for the peak year and 3 percent overall.[5]

It is also worth noting that even though the financing requirements expected for the Alcan system are large in an absolute sense, peak year requirements as a percentage of total market capacity are about the same as the peak year requirements for the Alyeska project in 1975. Yet no question of capital market capability was raised with respect to Alyeska.[6]

The above analysis shows that the Alcan project would not squeeze out most other investment. It is true it will have to compete for funds with different investments in the energy as well as other fields, but if the project offers a competitive return for the perceived risk, its securities will be purchased. The capital markets are probably the most competitive element in our economic system.

### Cost overrun financing

The question of how to finance cost overruns is closely related to the question of noncompletion. Once sponsor equity is invested, construction has started, and the lenders have committed to the project, it is unlikely that the capital markets would cease to provide funds simply because of higher than expected costs. The real

[4] The Alcan project is relatively more important to Westcoast and AGTL; together they have total assets of $1.6 billion at the end of 1976. Their equity investment in the project will be a major investment for them.

[5] It is not necessary to restrict the supply to these two domestic markets. Other international capital markets could be utilized. For example, in 1974 Canadian net foreign liabilities reached $3.0 billion in mid-year, up from $1.7 billion one half year earlier, when business loan demand rose abruptly and exceeded domestic liability expansion.

[6] Alyeska's peak year financial requirements, in light of capital market capability, were as follows:

1975 Alyeska Debt Issued, $3.0 billion.
1975 Total Corporate Debt Issued, $27.2 billion.
Peak Year as a percent of total issues, 11.0 percent.

consideration here is not the absolute level of costs, but the probability that the project would be ultimately successful. Analysis of the Alyeska experience shows that although the ultimate cost of the project was not known, as costs escalated lenders increased the amount of funds they were willing to provide on several occasions because they were convinced that the project would deliver oil at competitive prices. As a result, the risk of noncompletion due to cost overruns is insignificant once the project is under way, and is only a problem at the initial stage of financing. It is at that time that the lenders must be convinced that the sponsoring group will follow the project through to completion. Committing equity funds at the outset provides the basis for that assurance.[7]

The project sponsors alone cannot be expected to provide such assurances because of their limited assets, liabilities and cash flows; as a result, it is desirable to include in the sponsor group other beneficiaries as participants in the financing.

Project participants and beneficiaries

Tradition and equity suggest that the parties who stand to benefit directly from a transportation system participate in the financing and share the burden of these risks. The direct beneficiaries include the equity investors, namely a consortium of gas transmission companies; the producers of the gas; and the State of Alaska with its royalty interest in the gas.

Equity investors

The Alcan proposal was initially developed by Northwest Pipeline in conjunction with two Canadian transmission corporations, Westcoast Transmission Company and Alberta Gas Trunk Line and their subsidiary, Foothills Pipe Lines (Yukon) Ltd. Subsequently, the Alcan proposal has acquired the support of many large U.S. and Canadian gas transmission firms. An important advantage of the Alcan project over the El Paso alternative is the equity investment by Canadian transmission companies which will total at least $800 million.

The strength of the sponsoring consortium of gas transmission companies is a significant element of the financing. The consortium must have the ability to provide the sizable equity funds as well as the equity component of any cost overrun requirements. From the outset, Alcan will enjoy a strong consortium with participation by most of the large natural gas transmission corporations in both countries.

After careful study of their financial capacity, the conclusion has been reached that the natural gas transmission industry has ample capacity to provide the requisite equity commitments to the Alcan transportation project. The current members of the Alcan consortium are judged to be capable of meeting the equity requirements as proposed in the financing plan.

[7] An important element of this financial plan will likely be the commitment of equity capital "up front." In order to provide for the risk-bearing characteristic of having the equity component of budgeted cost be invested before debt, while simultaneously keeping the interest during construction as small as possible, it is contemplated that debt and equity shall be obtained simultaneously in their long-run proportion with equity commitments to be honored even in the event of noncompletion.

Producers of Alaskan natural gas

The owners and potential producers of Alaskan natural gas are primarily Exxon, Atlantic Richfield, and the Standard Oil Company of Ohio. These companies stand to benefit directly from the sale of their Prudhoe Bay natural gas reserves. Timely development of the Alcan system is in their best interests.

1. At the NEP price of $1.45 per mmbtu, the producers' constant 1977 dollar value of 23 Tcf of saleable reserves, net of royalty and severance taxes, is more than $30 billion.

2. Because of the time value of money, a field price that escalates more slowly than the amount producers could otherwise earn on the funds makes it more profitable to produce gas now rather than defer production for later.

Producer participation in the financing of the project is warranted due to their beneficiary status and their financial strength. The producing companies have the investment capacity to participate in the financing of a transportation system, especially as full returns from their North Slope oil and the Alyeska pipeline investment are realized. These three companies had total assets of $51.5 billion in 1976 and net income of $3.4 billion. Financial participation by the producing companies, most likely in the form of debt guarantees, can be structured consistent with the terms and conditions placed upon the producers in Section 5 of the *Decision*.

*The State of Alaska*

The State of Alaska could realize as much as $7.5 billion (1977 dollars) from the sale of Prudhoe Bay natural gas in the form of royalties and severance taxes. The State would also realize about $50 million per year in property taxes. Furthermore, the State will be able to utilize the pipeline for natural gas distribution and development within the State. Prudhoe Bay gas, including the State of Alaska's royalty gas, will be made available to local Alaskan communities along the route of the Alcan Pipeline System. Installation of additonal pipeline facilities connecting with the Alcan system could provide natural gas to other areas of the State, particiularly the Cook Inlet region and Southeastern Alaska, and thus supply the energy base required for long-term economic development. The Alcan system also will offer a readily accessible transportation service for a number of potential Alaska gas reserves located in interior Alaska, Cook Inlet and the Gulf of Alaska.

The State of Alaska has indicated a willingness and ability to guarantee up to $900 million of the El Paso project debt, with the final amount depending upon the percentage of royalty revenues that the State Legislature votes to have placed in a permanent capital account that can be used for such purposes. While no comparable commitment has been received from the State for the Alcan project, such participation by the State in the financing would be in the interest of the State, the Nation and the expeditious construction of the project.

## Transfer of financial risks

### Gas consumers

The issue of gas consumers bearing some or all of the financial risk of this project was widely discussed in the Federal Power Commission hearing and has been carefully considered in reaching the *Decision*. The most frequently discussed mechanism for consumer support would involve a consumer financial guarantee through an "all-events" tariff with noncompletion arrangements. The noncompletion guarantee would include a consumer guarantee of at least debt service, and possibly a return of equity, in the event the project was not completed.

The financial advisors and sponsors of the El Paso project continue to believe that consumer guarantees through the "all-events" tariff with noncompletion features is required to finance an Alaska gas transportation project. The Alcan financial advisors and sponsors, however, have stated in correspondence that in their professional opinion the Alcan project can be financed under certain conditions with a more traditional tariff, that is without consumer noncompletion guarantees or Federal financial assistance.[8] They now propose a tariff arrangement similar to previously approved arrangements for major projects which would provide for maintenance of debt service through consumer charges in the event of interruption only after the project is completed and initial operation of the delivery system has commenced.

The Agreement on Principles reached with Canada and the terms and conditions imposed in the *Decision* satisfy the conditions specified by the Alcan financial advisors. Their finding appears supportable and reasonable. Extraordinary consumer guarantees prior to completion of the project are judged to be unnecessary.

### *Federal Government financial assistance*

Federal Government support to the project in the form of loan guarantees or insurance has also received extensive scrutiny. The El Paso proposal anticipated approximately $1.5 billion of Federal loan guarantees for the financing of the LNG tanker fleet through the existing Maritime Administration Shipbuilding Program (under Title XI of the Merchant Marine Act of 1936). The Lead Agency Report to the President on financing demonstrated that new and special Federal financing assistance was not necessary.[9] El Paso did not request new forms of Government assistance for this project. The Alcan financial advisors believe there is no need for any Federal financial assistance.

In addition to being unnecessary, Federal financial assistance for this project is considered undesirable for the following reasons:

1. Serious questions of equity result from the transfer of risks to taxpayers, many of whom are not gas consumers or will not receive additional gas supplies as a result of the Alaskan project.

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[8] Memorandum from Mark Millard, Vice Chairman of Loeb Rhoades, dated Aug. 10, 1977, attached to a letter dated Aug. 10, 1977, from John McMillian, President of the Alcan Pipeline Company, to Secretary of Energy, James Schlesinger.

[9] Report to the President, Financing an Alaskan Gas Transportation System; Department of the Treasury Lead Agency, and other Participating Agencies, July 1977.

2. Federal financial support substitutes the Government for private lenders in the critical risk assessment function normally performed by private lenders.

3. A subsidy in the form of lower interest rates yields an artificially low price for gas.

4. The incentive for efficient management of the project is reduced.

5. The Government is placed in conflicting roles as guarantor and as regulator of the project.

6. Providing unnecessary Federal assistance to this project would set a precedent with respect to other large energy projects that is misleading and counterproductive.

Variable rate of return

Since the tariff will require gas consumers to pay for all costs except those found unreasonable by the regulatory authority, incentives to minimize cost overruns must be ensured. In order to give sponsors an incentive to control costs, the rate of return on equity should be tied to the size of the cost overrruns. Within certain maximum and minimum levels, return on equity would increase were the project to come in at or under budget but decrease were costs to exceed budget. Were the project under budget, consumers would pay a lower price for gas and sponsors would receive a higher return on equity. Were the project over budget, the higher total invested capital would be partially offset by a lower allowed rate of return on that capital, so that equity investors would assume part of the cost overrun. The variable rate of return offers consumers the possibility of lower costs and the sponsors compensation for risking their equity, and may assist in making this project attractive to equity investors. The details of how the variable rate of return will be implemented are left to the FPC and NEB to balance the economic incentive with administrative feasibility.

The combination of an economic project, adequate compensation of risk capital, and contingent financing agreements appear to minimize the risk of cost overruns as it relates to financing and the delivered cost of gas. With the cost overrun risk reduced to manageable proportions, the project will have a high probability of being successfully financed in the private sector.

Cost to the consumer

The aspect of the financing plan adopted here which will have the greatest effect on the total transportation cost paid by consumers is the assumption of the entire noncompletion risk by the project sponsors and other beneficiaries. The alternative would be to let consumers or taxpayers bear part or all of that risk through a noncompletion guarantee or through Federal government guarantees.

In the capital markets additional risks are assumed only if additional rewards are provided, and that principle is likely to operate in this instance. If the State of Alaska and the producers provided assurances for cost overrun financing, they would expect to receive some commitment or guarantee fee, although the amount of such fee should be relatively small given the small risk they are bearing.

Insofar as there is any risk, most of it will be assumed by the sponsors as equity capital investors. Under the plan recommended here, their equity would finance the first $2 billion of investment. They would, therefore, bear what little risk there is of project abandonment.

While it is difficult to give a precise value to this risk-sharing principle, the rate of return on equity used in develcping all the numerical analysis has been 15 percent rather than the more normal 12.5 to 14.0 percent found in recent FPC decisions. Thus, for example, the effect of changing the rate of return on equity from 13.5 percent to 15 percent is an increase in the average cost of service of about 4 percent.

This risk-sharing principle, however, provides an important incentive for efficient management and cost control that would be foregone if consumers or the Federal Government were to assume noncompletion guarantees. The effect of this incentive on total project costs may more than offset the direct effect on the rate of return associated with avoidance of consumer completion guarantees. Overall, therefore, the objective of placing the risk of noncompletion on sponsors and beneficiaries other than consumers appears equitable and cost-effective.

Financeability

In its *Recommendation to the President,* the FPC found:

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

This finding is no longer accepted in view of several recent developments. First, while El Paso requires less total initial outlay, approximately 20 percent of Alcan's total capital requirements are now anticipated to be drawn from the Canadian capital market. This sharing of the raising and servicing of Alcan's capital by the strong Foothills group makes the total U.S. capital requirements less for Alcan than El Paso.

Second, the cornerstone of financeability is economic viability. There is no doubt that Alcan's superior economic efficiency (lower operating cost and higher fuel efficiency), which has now been further assured by the Agreement on Principles, will make its financial instruments more attractive than those of the El Paso system.

In general, El Paso's dependence upon Federal Government support for financeability is not a particularly desirable characteristic. Overall, it is reasonable to conclude that Alcan will be at least as easy and probably easier to finance privately than El Paso.

Presidential finding that the Alcan System can be privately financed

The Alcan sponsors and financial advisors have stated the Alcan project can be privately financed. The financial analysis above supports this conclusion. Therefore, it is reasonable to anticipate that the Alcan project can be financed in the private sector.

Novel regulatory schemes to shift this project's risks from the private sector to consumers are found to be neither necessary nor desirable. Federal financing assistance is also found to be neither necessary or desirable, and any such approach is herewith explicitly rejected.

## CHAPTER III—ENVIRONMENTAL AND SOCIOECONOMIC CONSIDERATIONS

### THE ENVIRONMENTAL ADVANTAGES OF ALCAN

It is significant to note that the Alcan proposal was originally presented to the FPC after the preliminary environmental impact statements had been critical of both the El Paso and Arctic Gas proposals. The "Environmentally preferred route" suggested by the FPC staff early in the proceeding was followed closely by Alcan in developing its system. The success of the Alcan proposal is in large measure a result of its attention to environmental impact.

The environmental impact of large-scale construction in a northern environment is a particularly sensitive issue. The tundra and permafrost are delicate and slow to heal; the fauna is unaccustomed to the presence of large-scale human activities, and the breeding patterns and survival rate are easily upset. Endangered wildlife species cling precariously to existence; aquatic life is as sensitive as terrestrial life; and native populations must subsist on this fragile environment for their economic and physical well-being.

Many parties in both the U.S. and Canada contended that the Arctic Gas proposal, even if it was, as some claimed, superior on economic grounds, had the potential for substantial environmental and socioeconomic impact. The Arctic Gas route would not have followed existing utility corridors and would have cut through the Arctic National Wildlife Range in the northeast corner of Alaska. While Arctic Gas proposed mitigating measures that included, among other things, all-winter construction across the North Slope and above the 60th parallel with snow roads and work pads, some parties considered these measures technically unfeasible. The State of Alaska also opposed construction in the Range.

The Canadian National Energy Board found that the Arctic Gas route in Canada was "environmentally unacceptable" because it would have impacts "which could not be avoided, which could not be accepted, and for which mitigative measures are unknown or uncertain of development." This finding of the NEB effectively forced the withdrawal of the Arctic Gas proposal from further consideration.

On environmental and socioeconomic grounds both El Paso and Alcan are superior to Arctic Gas because they generally follow existing utility corridors where the incremental environmental impacts tend to be small. In this respect, the Alcan proposal is particularly advantageous. The Alcan route follows the Alyeska oil pipeline in Alaska until it turns to follow along the Alaska Highway into Canada at Delta Junction; from Delta Junction the pipeline will generally make use of the Alaska Highway right-of-way or the now-abandoned Haines-Fairbanks pipeline right-of-way (a line built during World War II to transport oil products to Fairbanks from Haines, which is north of Juneau, Alaska).

The environmental impact of the El Paso proposal, on the other hand, would be more adverse than Alcan's. After departing from the Alyeska corridor near Valdez, the El Paso route would traverse the wild and mountainous Chugach National Forest for about 40 miles, an area of great beauty which supports many forms of wildlife and has no roads. A gravel haul road and LNG plant could affect the bald eagles and Sitka black-tail deer that inhabit the area. Furthermore, El Paso would also have an adverse impact on the marine biota of Prince William Sound from the thermal, chlorine and other toxic material discharge of its LNG plant. The impact of this LNG plant would have to be mitigated by the addition of cooling towers—which have their own environmental impact—at an estimated 1975 dollar cost of $75 million. Similarly, El Paso's California regasification facility also has the potential for adverse impact on marine biota with its cold water discharge into the Pacific Ocean. By comparison to these impacts, no particular impact of Alcan has been singled out for the same degree of concern.

The environmental impacts of Alcan's eastern and western legs in the lower-48 states have never been considered serious. In the FPC hearing, Alcan showed sensitivity to a myriad of local impacts and suggested mitigative measures that appear adequate.

Finally, Alcan's far superior fuel efficiency means that the system will deliver more units of clean-burning and efficient natural gas than El Paso for the same amount of wellhead deliveries. Alcan is expected to consume only about three-fourths as much gas for fuel as the El Paso system.

### Presidential finding—environmental impact statements

In its *Recommendation to the President*, the Federal Power Commission found after months of hearings and evaluations of impact statements that "no doubt, the Alcan route promises the least environmental impact." In its subsequent July 1 Report, the Interagency Task Force on Environmental Issues, under the lead of Department of the Interior, concluded that Alcan appeared to have the least environmental impact of the proposed routes, provided that proper mitigative actions are taken. The conservationist intervenors in the proceedings (Sierra Club, The Wilderness Society, National Audubon Society, and the Alaskan Conservation Society) also stated a clear preference for the Alcan proposal.

Pursuant to Section 6(d) of ANGTA, the Council on Environmental Quality submitted a report on July 1, 1977, which found that the environmental impact statements submitted by the FPC with respect to Alcan, pursuant to Section 5(e) of ANGTA, are legally and factually sufficient.

After four days of public hearings, and extensive study, the CEQ reached the following conclusion: "Alcan is the environmentally preferable route. Its impacts are largely restricted to existing transportation corridors * * * and involve no large-scale intrusion into wilderness values." The CEQ also found that the information was insufficient to determine whether the El Paso project is environmentally acceptable. It is clear from the FPC hearings, the environmental impact statements prepared by the FPC and Department of the Interior the certification of those impact statements by the CEQ, and many other submissions from many parties that the Alcan route is clearly the superior system on environmental grounds.

The President hereby determines pursuant to the direction of Section 8(e) of ANGTA, that the required environmental impact statements relative to an Alaska natural gas transportation system have been prepared, that they have been certified by the CEQ and that they are in compliance with the Natural Environmental Policy Act of 1969.

Consequently the enactment of a joint resolution approving the *Decision* shall be conclusive as to the legal and factual sufficiency of the final environmental impact statements as provided by Section 10(c)(3) of ANGTA.

## SOCIOECONOMIC IMPACT

The socioeconomic impacts of both systems are roughly the same in Alaska. Under either proposal, the royalty, severance tax, property tax and income tax revenues to the State of Alaska will increase substantially. The Department of Commerce's *Report on Socioeconomic Impacts* found the El Paso proposal would provide a greater impetus to the Alaskan economy, but if factors such as adverse effects on native communities and local lifestyles are given primary importance, the Department concluded that the El Paso proposal would then suffer in comparison with Alcan.

On the basis of relative growth, Cordova, 13 miles southeast of Gravina Point, will suffer the most change with the El Paso project. Because of LNG plant and construction, the population would be expected to fluctuate from 2400 in 1977 to 9100 in 1979 to 4100 in 1982. As a result, the character of the town itself might change from a fishing village to an industrial town. The State of Alaska has noted that the socioeconomic costs to small communities will be greatest for the El Paso project.

Otherwise, it should be noted that both proposed pipelines follow existing utility corridors; the native communities near these corridors have already been affected by the pressures created from major construction activity. Accordingly, the socioeconomic impact of Alcan's construction, which more closely follows these corridors, should not be as great as El Paso's.

## CONCLUSION

To sum up, environmental values have been extensively considered and evaluated throughout the certification and decision process. In the future, Federal oversight of design and construction of the Alcan system should strengthen and implement the environmental priorities established in this decision process. Significantly, both the Administrator of the Environemental Protection Agency and the Secretary of the Interior will be represented on the Executive Policy Board. The Board, as discussed in Chapter VI of the *Report* and specified in Section 5 of the *Decision*, will provide policy direction through the Federal Inspector to the Agency Authorized Officers, including those from the EPA and Interior, who will directly represent and exercise the statutory authorities of their respective agencies. The strong representation of EPA and Interior on the Executive Policy Board will help ensure the protection of environmental interests through the enforcement activities of the Federal Inspector.

As required by ANGTA, environmental concerns have been paramount in the study and decision process, and will be translated into a responsive permitting and enforcement mechanism for implementation of the *Decision*. Federal oversight will seek to avoid "trade-offs" between protection of environmental priorities and construction economics by seeking through advance planning by the Government and the applicant for the coordinated enhancement of both.

## CHAPTER IV—ECONOMIC CONSIDERATIONS

### POTENTIAL FOR COST OVERRUNS AND TIME DELAY

The cost overruns that occurred in construction of the Alyeska oil pipeline naturally raise questions about the potential of any Alaskan natural gas transportation system for cost overruns. Such overruns can result from poor initial cost estimates, waste, institutional delays, inflation, low construction productivity, or management inefficiency. While it is difficult to assess the likelihood of such problems prior to the start of construction, they provide a useful basis on which to compare the respective projects. The major causes of cost overruns appear to be the following:

1. *Incentives to make a low initial cost estimate.*—In projects where institutional approval must be obtained prior to the start of construction, the project applicant may try to increase the chances for approval by conservative estimates of the project costs.
2. *Use of new complex technology or scaled increases in design size.*—Technologically uncomplicated systems are less expensive and have fewer uncertainties that increase capital costs.
3. *Labor productivity and equipment capacity.*—There is a well-recognized inverse correlation between productivity and the increasing utilization of the capacity in an industry. As the use of labor capacity, equipment capacity, or management availability approaches 100 percent, productivity begins to decline rapidly. Furthermore, the more complex the project, the greater the loss in productivity or efficiency as the project capabilities are reached or exceeded. When large-scale projects experience equipment and material shortages, they generate their own internal, demand-pull inflation, resulting in an increase in equipment and material costs.
4. *Cost of service tariffs and cost-plus contracts.*—Cost increases during construction of public utility projects merely expand the rate base of the utility; absent a variable rate of return, they do not result in any loss to investors. The same effect occurs from use of cost-plus contracts; the contractors' profit will not be adversely affected by cost overruns.
5. *Construction schedule pressure.*—In most situations, accelerated construction schedules can be accomplished only at a high premium in cost.
6. *Long delays after project start-up.*—Large scale projects are frequently delayed because of litigation, labor grievances, and cumbersome bureaucratic actions or regulations.
7. *Remote areas or inhospitable environments.*—Remote locations create severe logistical problems and magnify the costs of

poor planning. Breakdown of equipment that would cause only minor delays in well settled areas may result in considerable delays in remote areas. Furthermore, new techniques, methods, and materials are frequently required when work is done in an inhospitable environment. Such conditions often cause on-site modifications of equipment or design.

8. *Unforeseen geotechnical factors.*—Even to experienced geologists, the earth holds many surprises—especially in the Arctic. Unexpected water flows or earth movements can create severe construction problems and cause expensive delays. The unstable permafrost soils in the Arctic regions are particularly troubling for large-scale construction.

*Comparisions with Alyeska*

Both the Alcan and El Paso projects would encounter these problems to one degree or another. Like Alyeska, they have the potential for significant cost overruns. But when the Alyeska experience is examined, a convincing case can be made that the cost overruns for Alcan and El Paso would not be as great. The major problems described above provide a useful framework for comparison.

1. *Low cost estimates.*—The early cost estimates by Alyeska were made for a system smaller than the one Alyeska finally built. Alyeska had no appreciation at the time of these estimates for the vast changes in construction techniques that would be required for arctic construction by subsequently enacted environmental laws. Alyeska also had no experience with the logistics problems and low labor productivity characteristic of arctic construction. By 1974, Alyeska had become aware of the increased costs of environmental requirements, but still had no data on labor or contractor productivity in arctic conditions. By mid-1975, when Alyeska submitted its first design cost estimate of $6.3 billion, it had developed considerable experience with pipeline construction.

El Paso's cost estimates for Alaska construction of its 2.3614 bcfd case were submitted to the Federal Power Commission in late 1975 and Alcan's estimates were submitted in mid-1976. Thus, El Paso and, to an even greater degree, Alcan had the opportunity to factor into their cost estimates the Alyeska experience. While there are valid reasons to expect both Alcan's and El Paso's estimates to be conservative, there is little reason to expect that their initial estimates are as grossly under-estimated as the early estimates of Alyeska. Both projects had too much data and experience available to them to have made large errors, and excessive underestimates would have been challenged by competitors.

2. *New technology and increases in scale.*—While El Paso and Alcan involve some new technology and increases in scale, the problems from these factors will be of an order of magnitude less than Alyeska's. The large capacity systems of both projects require an increase in operating pressures. DOT has concluded, however, that subject to testing to be conducted by the applicant in conjunction with the U.S. and Canadian governments, such increases are within current technological capability and safety standards.

In addition, no scale-up in construction equipment (e.g., building equipment to handle 48-inch pipe) will be required for the gas pipeline. The problems of scale-up were mostly solved by Alyeska.

Thus, El Paso with its 42-inch pipe, or Alcan, with its 48-inch pipe, would have the benefit of using field-proven equipment.

The Alyeska pipeline also required a large amount of automated and sophisticated equipment. Remotely controlled "topping plants" (i.e., miniature refineries) and storage areas at pumping stations were used to provide the turbine fuel to drive the pumps. A separate gas pipeline was constructed to bring the fuel to the northernmost pump stations. In addition, Alyeska could not bury a hot oil line in the thaw-unstable permafrost. It had to employ considerably sophisticated and advanced technology to design the vertical support members and heat exchangers necessary to insulate the oil line from the surrounding environment. Approximately 400 miles or 50 percent of the line is elevated.

By contrast, a natural gas pipeline is a far more simple, less sophisticated system. Fuel for the compressor turbines is drawn directly from the gas stream, and controls are simple and easily automated. The chilled gas pipeline is compatible with the permafrost environment even in a buried mode. There are uncertainties regarding the best design and engineering to eliminate frost heave potential in discontinuous permafrost areas. However, this problem is not comparable in complexity or size with the problem of adapting a hot oil pipeline to the arctic environment.

Scale-up problems might generate cost overruns during construction of the El Paso natural gas liquefaction plant. The proposed LNG plant would require a significant scale-up from existing plants and involves lower fuel usage than has heretofore been achieved in practice. In addition, the techniques proposed to protect the proposed plant and storage tanks from earthquake damage would also require a size scale-up. Consequently, the LNG plant and terminal appear to have a potential for significant cost overruns.

3. *Labor and equipment capacity.*—The Alyeska project is a classic example of a construction project that exceeded its predetermined labor and equipment capacity. Alyeska was forced to use inexperienced labor and contractors, and thereby incurred significant increases in the size of management and engineering staffs. This resulted in low productivity, management inefficiency, and created the project's own internal demand-pull inflation for some critical items.

Construction of a gas pipeline in Alaska should present fewer problems. Less labor is required for a continuous buried mode of construction and the Alyeska experience expanded the pool of skilled workers and contractors available for arctic construction.

The Alcan project may encounter skilled-labor shortages in Canada. Anticipated shortages in skilled labor and experienced subcontractors could reduce productivity and raise costs. However, training programs and proper project planning would mitigate this problem.

Alcan has been criticized because it will not have an overall project manager. The Canadian companies, however, can control construction in their respective segments of the system without the large increases in management or engineering reqtired for a single project. In addition, the companies will be using control and accounting procedures with which they are familiar. It is reasonable to expect that Alcan will not suffer from the management and control inefficiencies that plagued Alyeska.

4. *Incentives to minimize construction costs.*—The El Paso and Alcan projects would have stronger incentives to control costs than are normally present in a public-utility type project. The variable rate of return will link the earnings of equity investors directly to the cost control performance of management. In Canada, the costs to Canadian consumers for Canadian gas will be materially dependent upon the level of cost overruns in the main Alcan line, providing Canadian regulatory agencies with an incentive to control costs.

One of the terms and conditions contained in the decision will limit the use of cost-plus contracts unless approved by the Federal Inspector. Contractors will thus have incentives to hold down costs. The magnitude of the project investment and the generally limited availability of capital at present will also create financial constraints that should act to minimize costs. Furthermore, the managements of the various gas companies also have a substantial incentive to show that a major arctic project can be constructed with relatively minor cost overruns.

5. *The time factor.*—With a simpler construction mode, fewer environmental problems, a more experienced labor force available, and more favorable terrain in most of Canada, construction of the Alcan system should pose fewer problems, and have a longer lead time to deal with them. While Alyeska had a long delay from 1969 to late 1973, there is little evidence that intensive planning occurred during that period. After Congressional approval came in late 1973, Alyeska carried out its final planning and construction in three and one-half years. The final planning and execution period for either gas project is at least five years and the overrun analyses herein have allowed for six to six and one-half years.

6. *Delays.*—The Alyeska project suffered excessive delays because of strict new environmental laws enacted after it had initially ordered the pipe and some construction equipment. Government agencies required considerable time to write regulations and to staff operations. In addition, after construction started, numerous government inspectors monitored contractors and subcontractors, occasionally shutting down construction.

Conditions should be considerably better during construction of the gas pipeline. First, the government itself is now more knowledgeable about the inspection process and can be expected to make fewer errors. The Office of Federal Inspector is designed to achieve greater coordination of the government monitoring and enforcement process. The occasionally conflicting orders given by different departments or agencies during construction of the Alyeska project will be avoided. Second, contractors have learned to some exent to adapt to the government inspection process. Third, the gas line will raise fewer environmental problems. Overall, delays resulting from environmental regulations and government oversight and inspection should be much less during construction of a gas pipeline.

The projects will also be much less constrained by institutional delays of the type that confronted Alyeska from 1969 until enactment of the TAPS Act in 1973. Similar to the TAPS Act, Section 11 of ANGTA contains tight restrictions on judicial review of the authorization and certification process. While private litigants can still challenge Government actions, such claims must be brought within 60 days of such action, and filed only in the U.S. Court of Appeals for the District of Columbia. This Court will act as a Special Court with exclusive jurisdiction over such matters. There are no specific limitations on judicial review of Federal enforcement actions, but it is not foreseen that such litigation will result in injunctions or restraining orders that increase the potential for delays and cost overruns.

El Paso and Alcan each face institutional barriers other than potential judicial delays. For El Paso, the problem of siting an LNG facility in California has high potential for delay. The Western LNG Terminal Company has been investigating proposed locations for approximately two years, and no final decision has yet been reached. Recently, an offshore LNG facility has been receiving consideration, but gas companies and State officials estimate that 8 to 10 years of design development and construction work would be required before it could be operational.

For Alcan, the problem of resolving native claims in the Yukon Territory in Canada had once threatened to delay construction. However, the Government of Canada has recently assured the U.S. that resolution of these claims will not delay construction and will not result in any monetary cost or claim against the Pipeline. Under the Agreement, it is expected that construction in the Yukon will commence by January 1, 1981.

In general, the magnitude of these projects virtually ensures some delay in the start of full operations—either because of material supply, logistics, reduced labor productivity or other problems. Therefore, this *Report* estimates that commencement of full operations for Alcan could be delayed to January 1, 1984, and for El Paso to July 1, 1984. By comparison, the Task Force Report on Cost Overrun and Construction Delay estimated a starting date of July 1984 for Alcan and February 1985 for El Paso.

7. *Remote and inhospitable location.*—Both projects would experience many of the same problems associated with remote locations as did Alyeska. The benefit of the Alyeska experience, however, should assist in coping more successfully with these problems. The most tangible benefit of the Alyeska experience is the existence of the infrastructure—e.g., roads, camps, communications—created by Alyeska. In Canada, the southern portions of the Alcan system would be in less remote locations and present fewer problems.

8. *Geotechnical considerations.*—Alyeska encountered many unexpected geotechnical conditions, but had done relatively little advance coring and soil testing which could have reduced the unexpected problems that arose later and allowed for improved engineering design and scheduling of work requirements.

Either of the gas pipeline projects will be able to reduce its number of site-required design changes by using the construction data generated by Alyeska and by carrying out a more extensive coring and soil testing program prior to construction. In addition, the site-specific design changes that were required will probably be less expensive.

Unexpected geological conditions could significantly increase the cost of constructing an El Paso LNG plant and shipping terminal. Similarly, Alyeska experienced significant cost overruns in constructing the Valdez terminal. El Paso probably would escape such problems if, as expected, it finds shallow bedrock at the Gravina Point terminal site. If not, El Paso could duplicate or exceed the Valdez terminal cost overrun.

Cost overrun estimates under expected conditions

Comparison of the El Paso and Alcan projects under expected conditions with Alyeska indicates that both projects would be able to avoid or minimize many problems that led to high cost overruns for Alyeska. Cost estimates of both projects appear to be based on much more reliable data and experience. There are also fewer uncertainties than were associated with Alyeska's early estimates, or even its estimates made as late as 1974 or early 1975. In addition, several problems that significantly contributed to cost overruns on the Alyeska project will not be as serious for these projects. While overruns can be expected, they will be of relatively lower magnitude than Alyeska's.

Obviously, any prediction of future cost overruns is highly judgmental. Specifically, it depends on judgments about future productivity, future supply-demand relationships, and geological and technical problems. But despite these uncertainties, for the purpose of this analysis some judgments must be made.

Overall, it has been estimated that cost overruns of 30 percent or more should be expected in Alaska and Canada for construction of a gas transportation system. But in many areas, the managers of a gas transportation project should benefit from the Alyeska experience and hold down overruns. This conclusion is based on careful comparison with the Alyeska experience and proceeds from the findings of the July Task Force Report on Cost Overruns and Construction Delays.

Certain distinctions, however, should be drawn between Alcan and El Paso with regard to cost overruns. For Alcan, the cost estimates in Canada are substantially lower than the cost estimates for equivalent work done in Alaska. These estimates are highly uncertain. Alcan offers several explanations for the significant differential between costs to do the same job in Alaska and Canada. It contends that wage rates in Canada are about one-half the level in Alaska and that the productivity of labor in Canada has historically been higher. Futhermore, with the exception of the Yukon section, the Canadian terrain is typically much better. Below the 60th parallel, the requirement for gravel work pads is minimal. As the line moves into British Columbia and Alberta, the Alcan construction conditions will not vary materially from those encountered in the Northern United States, and lower construction costs can be expected.

On the other hand, the NEB closely examined Alcan's costs in Canada and concluded that cost overruns in the range of 20 to 30 percent were "not unlikely". Furthermore, it is significant that the Alcan productivity estimates for Alberta are substantially higher than the estimates of Arctic Gas for comparable terrain. The Alcan cost estimates must be substantially adjusted to enable a realistic comparison between Alcan and El Paso. Therefore, the cost estimates used herein provided for a 40 percent increase in the filed costs of Alcan for Canada.

The cost estimates of El Paso are in turn, subject to two major uncertainties. The first is El Paso's cost estimates for pipeline construction in Alaska. El Paso estimated these costs, including interest during construction, at $2.204 billion ($1975)—$242 million less than Alcan's Alaska estimates of $2.446 billion. The relation between the El Paso cost estimates and the Alcan cost estimates is simply not consistent, however, with the physical plant requirements, but may be partially explained by the fact that the El Paso estimates were made several months earlier.

The higher Alcan estimates represent 731 miles of pipeline in Alaska, 9.6 percent less mileage than El Paso's 809 miles.[10] While Alcan would use a larger diameter pipe (48-inch for Alcan, 42-inch for El Paso), it would also have a thinner wall (0.60 inch for Alcan, 0.752 inch for El Paso). Consequently, Alcan would require about 17 percent less pipe steel in Alaska than El Paso. This differential is reflected in the respective cost estimates of the parties. The El Paso estimated materials cost for pipe was $805 million. Alcan estimated $659 million, or some 18 percent less. Finally, El Paso could have 10 compressor station sites in Alaska; Alcan would have only 8 sites. El Paso would have 234,000 installed compressor horsepower; Alcan would have 212,000 horsepower.

On the other hand, Alcan would have more installed refrigeration horsepower than El Paso, and installation costs for 48-inch pipe would be slightly higher than those for 42-inch pipe. The following Exhibit summarizes the comparisons.

EXHIBIT 3.—COMPARISON OF EL PASO AND ALCAN PIPELINE FACILITIES IN ALASKA

| | El Paso (2.4 Bcfd) | Alcan (2.4 Bcfd) | Percent |
|---|---|---|---|
| Miles (L) | 809 | 731 | −9.6 |
| Pipe | 42" (D) x .75 (T) | 48" (D) x .60 (T) | |
| Relative steel factor (π DTL) | 8.006 | 6.614 | −17.4 |
| Pipe material est. | $805,171,000 | $659,239,000 | −18.1 |
| Compressor stations | 10 | 8 | −20.0 |
| Compressor HP installed | 234,000 | 212,000 | −9.4 |
| Refrigeration comp. installed | 53,690 | 84,470 | +57.0 |

By way of further comparison, Alcan and El Paso propose virtually identical alignments for the first 539 miles in Alaska. The overall costs of the two systems should be comparable to that point. At Delta Junction, the Alcan line departs from the Alyeska corridor and proceds southeast along the Alcan Highway. The El Paso line continues along the Alyeska corridor to a point about 40 miles from Gravina Point, from which it creates a new right-of-way through the mountainous Chugach National Forest. From the common point of Delta Junction southward, Alcan would traverse 192 more miles in Alaska, while El Paso would traverse abut 265 miles and

[10] There would be 831 miles for the realignment which El Paso now proposes to build. The comparisons here consider only the base cases of El Paso and Alcan. El Paso estimated the realignment to have a net cost of about $70 million additional.

some significantly more difficult terrain.[11] There is no readily apparent reason that the 192 miles of Alcan pipeline should cost significantly more than the 265 miles of El Paso pipeline.

The proper relationship between El Paso and Alcan is reflected in the recently released Aerospace, Inc., study of June 1977 that was prepared for the Department of the Interior. The direct cost estimates therein for the El Paso pipeline in Alaska are $1.963 billion. The cost estimate for a 48-inch, 1680 psig [12] pipeline along the Alcan base route in Alaska is $1.812 billion.

To allow for cost overruns the El Paso estimates were escalated by the same amount used by the Cost Overrun Task Force to arrive at $2.5 billion in direct costs (1975 dollars) or $2.85 billion (1975 dollars) including interest during construction (IDC). The overrun case for Alcan used here is $2.38 billion in direct costs, $2.67 billion including IDC. These figures provide a better comparison between Alcan and El Paso in Alaska.

The second major uncertainty for El Paso is the cost of the LNG liquefaction plant and marine terminal on Prince William Sound, Alaska. The scale up factor and the geotechnical uncertainties create a high risk of substantial cost overruns. The Cost Overrun Task Force estimated the cost of these facilities to be $2.0 billion. The Aerospace, Inc., study estimated $1.59 billion. The estimates here used allow for $1.8 billion, plus $75 million to cover cooling towers that would likely be required to minimize the thermal pollution of Prince William Sound.

El Paso would also construct eight LNG tankers of 165,000 to 175,000 cubic meter capacity ($m^3$) with roughly 125,000 tons displacement.[13] El Paso estimates the LNG tanker cost at $1.365 billion. The Cost Overrun task force estimated $1.65 billion; Aerospace, Inc. uses $1.234 billion. The evidence submitted by Arctic Gas in the FPC proceeding shows an 8.8 percent overrun or $1.485 billion, and in fact, the most probable estimate is $1.45 billion.

In the lower 48 States, the facilities for El Paso and Alcan present no unique construction problems. Therefore, the cost overrun case used herein assumes only a few percent overrun for these facilities.

The following table sets forth the estimated capital costs for the base and overrun cases. The capital cost or the gross plant in service is a dominant element in the cost of service and net national economic benefit calculations.[14]

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[11] The El Paso realignment case has about 285 miles beyond Delta Junction.

[12] This would be more expensive than Alcan's 48-inch, 1260 psi system because of more pipe steel.

[13] The ultimate size of the El Paso ships would be determined by the siting of the regasification facility in California. For example, if Point Conception was the site, 165,000 $m^3$ would be adequate. If Oxnard was the site, 175,000 $m^3$ would be required. See FPC, *Recommendation to the President*, pp. VIII—26–28.

[14] NNEB calculations, however, use only the direct capital costs, without interest during construction.

## CAPITAL COSTS

[In billions of dollars]

| | Base case [2] (Current dollars) | Overrun case | |
|---|---|---|---|
| | | Current dollars | 1975 dollars |
| Alcan: [1] | | | |
| Alaska | 3.335 | [3] 4.147 | 2.673 |
| Canada | 4.365 | 6.501 | 4.191 |
| Northern Border | 1.427 | 1.573 | 1.014 |
| PGT, PG&E | .914 | .983 | .634 |
| Subtotal | 10.041 | 13.204 | 8.511 |
| U.S. share of Dempster line | .431 | .653 | .382 |
| Subtotal | 10.472 | 13.857 | 8.893 |
| Less Canadian "Share" | (1.000) | (1.489) | (.960) |
| U.S. "Share" of capital cost | 9.472 | 12.368 | 7.933 |
| El Paso: | | | |
| Alaska Pipeline | 3.050 | 4.419 | 2.849 |
| Alaska LNG | 2.385 | 3.289 | 2.120 |
| Ships | 2.027 | 2.285 | 1.473 |
| Regas Plant | .542 | .674 | .434 |
| Lower 48 | .991 | 1.032 | .665 |
| Total | 8.995 | 11.699 | 7.541 |

[1] Based on a 48-inch 1680 psi system between Whitehorse and James River capable of transporting 3.6 bcfd. If a 54-inch 1120 psi system was constructed, the capital costs could be slightly less.
[2] Derived from the 1975 Direct Capital Costs submitted by the applicant.
[3] The Base cases assume completion one year earlier than the overrun cases which accounts for a portion of the difference.

The foregoing table includes all capital costs in Canada in which the U.S. shares. If the Dempster Line is never constructed, the capital cost on the main line in the overrun case would be $6.111 billion (1984 dollars) because of the reduced compression horsepower requirements. Total U.S. share of capital cost would be $12.767 billion.

### COST OF SERVICE

The cost of service advantage of the Alcan overland pipeline system is substantial and constitutes a crucial element of this decision. Cost of service is perhaps the principal factor in determining the value of the project to individual consumers. If the cost of service is not sufficiently low enough to ensure that the delivered cost of the gas will be below the cost of alternative fuels, the value of the project is greatly reduced.

A cost of service calculation generally includes all transportation charges other than fuel expense. The major cateogries of expense include the return on invested capital (interest and dividends), return of invested capital (through annual depreciation charges), Federal and State income taxes, other taxes, and operating and maintenance expenses (O&M). While annual depreciation charges are constant throughout the depreciable life of the project and O&M expenses tend to increase with the rate of inflation, the other items decline over time as the amount of net invested capital (gross plant less accumulated depreciation) falls.

These declining items usually result in a project cost of service that decreases steadily over time, with the extent of the decrease dependent upon the rate of inflation. Although this decreasing cost of service is customary, a downward-sloping service charge to the consumer over the life of the project is not essential. Payments from consumers can be adjusted to a more constant or stable level over the accounting life of the project.

However, to compensate investors for deferral of their return in the early years of the project, and to cover the resultant increase in the total interest burden, the average delivered cost of the gas to consumers must be increased substantially; a complete leveling would increase the average cost about 20 percent over the life of the project. The decision whether to "level out" the tariff must be made by the FPC in the context of the actual financing and tariff proposals made by the applicants prior to final certification.

Alcan and El Paso: Cost of service comparison

The fundamental difference between El Paso and Alcan is that an overland pipeline system is inherently more efficient than an LNG transportation system. The liquefaction process involves significant energy losses that have a multiplying adverse effect upon cost of service. First, the direct cost[15] for the natural gas consumed by El Paso is 34 percent higher than Alcan or equivalent to 3 cents per mmbtu (1975 dollars). Second, the volumes of gas delivered are reduced thus leaving a 3.4 percent smaller base over which to spread the capital costs. The increase in cost of service for this volume differential is about 4 cents per mmbtu. The El Paso system also has 100 percent higher operating cost, or the equivalent of another 9.5 cents per mmbtu increase in the cost of service. This operating cost differential is attributable to the added labor required to operate the Alaska LNG plant and the LNG tankers. In sum, the Alcan pipeline system has a 16.5-cent direct advantage apart from capial cost of financing consideration.

The El Paso cost of service would approach the Alcan cost of service only if the more technologically complex El Paso system could be constructed for about 25 percent less than the portion of the Alcan system attributable to the U.S. There is no basis for such a conclusion. No reasonably plausible independent assessment of capital costs, suggests that to be a possibility.[16] On the basis of filed costs, the El Paso 20-year average cost of service is $1.09 per mmbtu; Alcan's is $.81 per mmbtu,[17] or $.28 less. The Cost Overrun task force "expected case" cost of service was $1.26 for the El Paso system and $1.09 for the Alcan system, or $.17 less.

COMPARATIVE SYSTEM COST ECONOMICS COST OVERRUN CASE

| | El Paso | Alcan [1] | Alcan [2] |
|---|---|---|---|
| Direct cost (in billions of 1975 dollars) | $6.800 | $7.166 | $8.011 |
| Interest during construction | $0.740 | $0.767 | $0.882 |
| Total capital cost (in billions of 1975 dollars) [3] | $7.540 | $7.933 | $8.893 |
| Annual O&M costs (in millions of 1975 dollars) | $168 | [4] $84 | |

[15] Consistent with practice throughout the Report the fuel cost is assumed to be $1.00 per mmbtu (1976 dollars). This unquestionably is lower than actual cost will be. A higher fuel cost would increase El Paso's cost of service to a relatively higher degree than Alcan's.

[16] The overrun case used herein places El Paso 5 percent lower; the July 1 task force "expected case" placed El Paso 4.2 percent lower, of course, not including the adjustments resulting from the Agreement on Principles with Canada.

[17] Not including a U.S. share of the Dawson Spur which on filed costs would be $.0479.

COMPARATIVE SYSTEM COST ECONOMICS COST OVERRUN CASE—Continued

| | El Paso | Alcan [1] | Alcan [2] |
|---|---|---|---|
| Annual fuel cost @ \$1/mmbtu (millions) | \$106 | | \$79 |
| Annual U.S. delivered volumes[5] (Tbtu) | 888 | | 918 |
| Fuel efficiency (percent) | [6]89.1 | | 92.1 |
| Average U.S. cost of service (in billions of 1975 dollars): | | | |
| First 5 years | \$1.84 | | \$1.71 |
| Second 5 years | 1.28 | | 1.13 |
| Third 5 years | .95 | | .77 |
| Fourth 5 years | .77 | | .57 |
| 20-year average | 1.21 | | 1.04 |
| Net national economic benefit (in billions of 1975 dollars) | 4.63 | | 5.77 |

[1] Direct and total capital costs are complete Alaska and lower-48 costs plus the U.S. share of these costs for the section of the system in Canada plus 83.3 percent of the Dawson-to-Whitehorse section of the Dempster line.
[2] The direct and total capital costs are the complete cost of the entire system, including the Canadian section of the main line in its entirety, plus 83.3 percent of the Dawson-to-Whitehorse section of the Dempster line.
[3] In current dollars, at an assumed inflation rate of 5 percent, the total capital costs are \$11.7 billion for El Paso and \$12.4 and \$13.9 billion for the U.S. allocated and total Alcan system, respectively. See p. 157.
[4] Based on U.S. share of costs in the sections of the system carrying both United States and Canadian volumes, plus 83.3 percent of O&M costs on the Dawson-Whitehorse section of the Dempster line.
[5] Based upon 2.4 bcfd at 1138 Btu/cf input at Prudhoe Bay and each system's fuel efficiency. The El Paso system as filed is designed to transport and liquify slightly lower volumes (2.3614 bcfd) at slightly lower Btu content (1130).
[6] Excludes bunker oil consumption by El Paso tanker fleet which would further reduce overall system energy efficiency to 87.5 percent.

As indicated in the following Table, the overrun cases used in the *Decision* and *Report* place the cost of service at \$1.21 for El Paso[18] and \$1.04 for Alcan.[19] This is a \$.17 difference. Over the first 20 years alone, the overland pipeline system will save consumers conservatively about \$6 billion (nominal), and average of \$300 million per year. Further, savings will continue long into the future. The Prudhoe Bay field is expected to produce gas in significant volumes for more than 25 years. The pipeline facilities will have a useful life in excess of 40 years.

Alcan cost of service pursuant to the agreement on principles

The Alcan cost of service must be analyzed from the perspective of both the Canadian National Energy Board (NEB) Decision and the Agreement on Principles between the United States and Canada.

The NEB decision provided for a rerouting of the Alcan main line through Dawson City, Yukon, to facilitate the transportation of up to 1.2 bcfd of Mackenzie Delta reserves. That rerouting would have compelled the expenditure of \$600 million at least two to three years prior to the time it would be needed and would have added further interest costs of \$150 to \$240 million. If Canada did not construct the Dempster Line, the U.S. consumer would have paid more than \$2 billion over the life of the project for no reason.

If the Dempster Line had been constructed, and 1.2 bcfd of Canadian gas flowed, the U.S. cost of service would have increased

[18] Apart from cost overruns, the principal variable in the El Paso cost of service is financing costs. The \$1.21 per mmbtu cost of service is based upon 8.5 percent cost of debt for the LNG tankers on the assumption that the MARAD guaranteed loans be available. The return on equity for the ships is 17 percent calculated on a discounted cash flow basis, as filed by El Paso. The overall cost of the remainder of the capital is dependent upon the debt-equity ratio assumed and whether and how much preferred stock could be used. These matters have been the subject of considerable debate through the proceeding. The capital structure used here is the same as that assumed for Alcan, 75–25 debt-equity ratio, 15 percent return on equity, 10 percent cost of debt. Under various other assumptions, the cost of service could be between \$1.19 and \$1.21.
[19] Including the cost of the U.S. share of the cost of the Dawson Spur.

from $1.07 to $1.12 per mmbtu because of system inefficiencies. The amount of natural gas delivered to the U.S. would have decreased by about 40 Tbtu annually. As a result of these lost volumes and inefficiencies, the cost to American consumers would still have been $2 billion more over the first 20 years than the project which emerged from the Agreement on Principles.

The project authorized in the Agreement on Principles also represents one of those unique, rare negotiating results in which both parties can justifiably claim to have improved their position over the starting point—the original NEB decision. This is apparent from the following comparison.

| | Agreement on principles | | NEB decision | |
|---|---|---|---|---|
| | United States | Canada | United States | Canada |
| Dempster line not constructed: | | | | |
| Cost of service [1] | $1.00 | ............ | [2] $1.07 | ............ |
| Fuel usage (percent) | 6.1 | ............ | 6.7 | ............ |
| Dempster line constructed: | | | | |
| Cost of service | $1.04 | $1.23 | $1.12 | $1.43 |
| Fuel usage (percent) | 7.7 | 7.3 | 11.2 | 9.7 |

[1] U.S. cost of service is the 20-year average in 1975 dollars. Canadian cost of service is for 1985, in nominal dollars.
[2] Including the $200 socioeconomic payment recommended by the NEB.

The Agreement on Principles contemplates that a higher capacity system [20] will be constructed from Whitehorse to the James River. If Canada does not construct the Dempster Line, the United States would bear the full additional cost of the higher capacity system. The cost of service data contained in this analysis is based upon a 48-inch, 1680 psi system from Whitehorse to James River. The 1680 psi system is slightly more efficient in the 3.6 bcfd range than the 54-inch, 1120 psi system. Thus, if the 54-inch system ultimately is installed, the U.S. cost of service would be higher by about 1 percent in all cases except where Canada does not construct the Dempster Line.[21]

If a 1680 system is installed and Canada does not build the Dempster Line, the 20-year average U.S. cost of service would be about $1.00. The system would have lower fuel and operating expenses than a 1260 system but the savings would not be quite sufficient to offset carrying charges on the increased capital outlays. On the other hand, the system does provide a large amount of inexpensive expansibility that would be used in the event significant new finds of natural gas are made in Alaska.

If Canada builds the Dempster Line and deliverability from the Mackenzie Delta is 1.2 bcfd, the cost of service will vary with the level of cost overruns on the mainline system in Canada and on the Dawson Spur. From a 0 to 35 percent cost overrun, the U.S. would pay 100 percent of the Whitehorse to Dawson section. At the expected 40 percent case, the U.S would pay 83⅓ percent or the ratio of U.S. to joint volumes at Whitehorse, whichever is higher. At 45 percent and over the U.S. would pay 66⅔ percent, or the ratio of U.S. to joint volumes at Whitehorse, whichever is higher.

[20] T1Either a 48-inch, 1680 psi or a 54-inch, 1120 psi are the most likely alternatives. The selection will be determined after a joint testing program is completed.
[21] T1At 2.4 bcfd, the 54-inch, 1120 psi system would be slightly more economically efficient. It has a lower initial capital cost.

In the cost overrun range of 35 to 45 percent, the U.S. share would vary linearly from 100 percent to 66⅔ percent, unless the actual volumes of U.S. gas in the line commit the U.S. to provide a greater share.

In the lower cost overrun case of 35 percent or below, under which the U.S. would be required to pay the entire cost of the Dawson Spur, the cost of service reduction from such overrun savings on the main line would more than offset any increase in cost of service resulting from increasing to 100 percent the U.S. share of the Dawson to Whitehorse segment. For example, with an overrun of 25 percent in Canada, the U.S. pays 100 percent. In this example, the average U.S. cost of service over a twenty year period would be approximately $1.00 per mcf (1975 dollars), or 4 cents less than the expected overrun case of 40 percent under which the U.S would pay only 83⅓ percent of the Dawson Spur instead of the 100 percent the U.S. would pay in the 25 percent overrun case.

The agreement also imposes a ceiling on U.S. liability for the Dawson Spur of 35 percent above filed costs. The Canadians, in turn, can credit all the cost overrun savings they achieve on the main line system carrying just Canadian gas, and ⅔'s (or relative volumes) of such savings on the shared system, against their cost overruns on the Dawson to Whitehorse section. Finally, the U.S share of the Dawson Spur cost of service can never be less than the U.S. percentage of actual volumes at Whitehorse, multiplied by the actual costs of the Dawson Spur, notwithstanding the Dawson Spur ceiling and the overrun formula. This last condition is only relevant in the case where substantial overruns in excess of *50 percent* are experienced on the entire system.

This agreement creates new incentives—on a portion of the project within Canada's jurisdiction and not otherwise subject to our control—which could significantly lower the cost of service to the U.S. and at the same time enhance the project's financeability.

The application of these principles in varying factual situations is illustrated by the following table.

| | Main line cost overrun (percent) | Dawson Spur cost overrun (percent) | U.S. base COS[1] | Dawson spur COS U.S. | Total U.S. COS |
|---|---|---|---|---|---|
| 1 ...... | 25 | 25 | 0.9556 | 0.0567 | 1.0122 |
| 2 ...... | 30 | 30 | .9679 | .0601 | 1.0280 |
| 3 ...... | 30 | 50 | .9679 | .0717 | 1.0396 |
| 4 ...... | 30 | 100 | .9679 | .0692 | 1.0371 |
| 5 ...... | 35 | 35 | .9822 | .0606 | 1.0478 |
| 6 ...... | 40 | 35 | .9927 | .0505 | 1.0432 |
| 7 ...... | 40 | 40 | .9927 | .0505 | 1.0432 |
| 8 ...... | 45 | 35 | 1.0047 | .0404 | 1.0451 |
| 9 ...... | 45 | 45 | 1.0047 | .0436 | 1.0483 |
| 10 ...... | 50 | 50 | 1.0130 | .0480 | 1.0810 |
| 11 ...... | 50 | 100 | 1.0130 | .582 | 1.0712 |

[1] Assumes volumes of 2.4 bcfd from Prudhoe Bay and 1.2 bcfd from the Mackenzie Delta.

Lines 1 and 2 represent 25 percent and 30 percent cost overrun cases for both the main line and the Dawson Spur. Under the Agreement, the U.S. would pay 100 percent of the Dawson Spur cost of service.

Line 3 provides an example of the crediting mechanism between the main line and the Dawson Spur. The 30 percent cost overrun would result in a capital savings of about $245 million below the 35 percent cost overrun. Assuming that U.S. and Canadian volumes are 2.4 bcfd and 1.2 bcfd, respectively, and all of the cost reduction is on the main line south of Whitehorse, Canada would have a credit of $163 million to apply to the cost of the Dawson Spur. A 50 percent cost overrun on the Dawson Spur would be only $81 million greater than a 35 percent cost overrun. Thus, Canada would have a sufficient credit to hold the U.S. share to 100 percent.

The case in Line 4 assumes a 100 percent cost overrun on the Dawson Spur.[22] The Canadian credit here also would be $163 million. The Dawson Spur (DS) adjustment is determined by the following formula:

1.35 filed DS cost (base)/actual DS cost minus credit

Applied to this case, the formula is:

733/1084 – 163=.7959DSCOS(.0869)=.0692

for the Dawson Spur cost of service.

Note that the U.S. contribution to the Dawson Spur is slightly less in this 100 percent Dawson Spur overrun case than in the 50 percent overrun case. Under the agreement, the U.S. share of the Dawson Spur cost of service decreases from 100 percent to 66⅔ percent in this instance depending on the overrun level of the Dawson Spur. This increase in capital costs of the Dawson Spur above a 35 percent overrun level has a greater impact under the formula in reducing U.S. cost of service share than it has in increasing the full Dawson Spur cost of service. This is so because full cost of service contains fixed costs that do not vary with capital cost overruns (e.g., operating and maintenance expenses). The greater the percentage of fixed costs, the less cost the overall cost of service will increase because of a given addition to capital costs.

While this precise effect (i.e., reduction in U.S. share where cost overruns are higher) would not obtain if the system was more capital intensive, e.g., a 36-inch or 42-inch pipe was installed, the general direction would be the same. Cost overruns on the Dawson Spur will not have a significant impact on U.S. cost of service in any case where the 66⅔ percent floor is not reached.

The case in Line 5 is the "base" case. There are no credits available from main line construction. The Dawson Spur overrun is 35 percent. The U.S. would pay 100 percent of the Dawson Spur.

In the example on Line 6, the U.S. share of the Dawson Spur is at 83⅓ percent because of the 40 percent overrun on the main line.

In the case represented by Line 7, the base U.S. share is 83⅓ percent, but the Dawson Spur adjustment operates since Dawson Spur overruns are above 35 percent. The result is:

733/760=.9645.833=.8034.0629=$.0505

for the Dawson Spur cost of service, and $1.0432 overall.

[22] This assumes a very unlikely occurrence in light of the cost of the main line.

In Case 8, the U.S. share of the Dawson Spur has declined to 66⅔ percent (or a volumetric share) because of overruns on the main line.

In Cases 9, 10 and 11, the mainline overruns have caused the U.S. share of the Dawson Spur to decline to 66⅔ percent. Since the 66⅔ percent floor has been reached, the U.S. pays that percent of total Dawson Spur cost of service, or .667.0650=$.0436 for the Dawson Spur cost of service in the 45 percent case. In the 50 percent case, the Dawson Spur cost of service would be .667.0717=$.0480. In the 100 percent case, it would be .667.0869=$.0582.

All of the above capital cost and cost of service data assume that the input volumes of gas will be 2.4 bcfd for the U.S. and 1.2 bcfd for Canada. On the basis of present geological information, 2.4 bcfd from Prudhoe Bay is more likely than 1.2 bcfd from the Mackenzie Delta. Deliverability from the presently proved reserves in the Mackenzie Delta more likely would be in the range of .7 to .8 bcfd. A reduction in Canadian volumes would, of course, substantially increase the U.S. share of the system in Canada. However, it would not materially alter the U.S. cost of service. If the joint system was designed for 3.1 to 3.2 bcfd, the capital costs would be lower by about $100 million, the U.S. operating expenses would be lower, fuel consumption would be lower in absolute and relative terms, and the delivered volumes would be higher. These cost reduction factors would offset the increase caused by the larger U.S. share of the base capital costs of the mainline system. For example, at 1.2 bcfd from Canada with a 40 percent overrun in Canada, the base U.S. cost of service would be $.9927. With the system redesigned for .7 bcfd from Canada, the U.S. cost of service would be $.9950.

The capital cost, operating expenses and delivery factors operate as well with respect to the cost-sharing on the Dawson Spur. To illustrate, the estimated overall U.S. cost of service at 3.6 bcfd (2.4 plus 1.2) in the overrun case is $1.0432. With 3.1 bcfd (.07 bcfd of Canadian gas) the U.S. cost of service would be slightly lower, about $1.035.

## NET NATIONAL ECONOMIC BENEFIT

The net national economic benefit (NNEB) to the United States of the Alcan project also substantially exceeds that from the El Paso project. The NNEB measures the desirability of a project from the public perspective. The NNEB of a project is the present value of the benefits derived less the present value of the resources employed in undertaking the project. The benefit is measured by the value of energy delivered to the lower-48 States. A value of $2.62 per mmbtu for natural gas in 1975 dollars was used throughout the FPC hearings and is based upon a study done for the Department of the Interior that was market oriented rather than resource oriented. This value also formed the basis of the NNEB calculation contained in the National Economic Impact Task Force Report of July 1977.

To ascertain the reasonableness of this value, the resource cost of the most probable substitute for natural gas, No. 2 distillate, was determined. Based upon a mid-1977 price of $14.50 per barrel for imported oil and plausible assumptions regarding producer taxes and the resource investment that is required to refine crude to obtain No. 2 distillate, \$2.60 per mmbtu is a fair measure of the current resource cost of this substitute for natural gas.[23]

Further, the real value of natural gas is likely to increase over time as the real cost of imported oil increases. If the real value of gas increases at a rate of only 2 percent per year, the value of the gross benefits determined herein would increase approximately 35 percent, and the NNEB would approximately double.

There are five general categories of resource costs used in the NNEB calculation: the Prudhoe Bay field costs of conditioning the gas and using water injection in place of reinjected gas to pressurize the field; the initial capital costs of the transportation systems; annual operating and maintenance costs; the costs of public services used to support the project (measured in terms of the property taxes the project will be required to pay); and, in the case of Alcan, the annual cost of service payments to Canada for transporting the gas.[24]

The components underlying these benefit and cost factors are displayed in Exhibits 4 and 5, and the NNEB components are summarized in Exhibit 6 for El Paso and Alcan under the cost overrun case herein. Alcan's NNEB exceeds that of El Paso by over \$1.1 billion, which is approximately 25 percent of the El Paso NNEB. Most of that difference is attributable to the reduced volumes of gas that El Paso would deliver because of its high fuel consumption. The real resource cost associated with the transportation are nearly equal, with the higher sum of the Alcan facilities, plus Canadian cost of service for Alcan, being offset by El Paso's large operating and maintenance expenditures.

EXHIBIT 4.—ALCAN NNEB COMPONENTS

[Dollar amounts in millions]

| Year | Delivered gas (trillions Btu's) | Field gathering and conditioning | Field operation and maintenance | U.S. transport facilities | U.S. working capital | U.S. operation and maintenance | Other U.S. taxes | U.S. share Canadian costs |
|---|---|---|---|---|---|---|---|---|
| 1977 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1978 | 0 | 0 | 0 | \$10.0 | 0 | 0 | 0 | 0 |
| 1979 | 0 | 0 | 0 | 40.0 | 0 | 0 | 0 | 0 |
| 1980 | 0 | \$200 | 0 | 240.0 | 0 | 0 | 0 | 0 |
| 1981 | 0 | 344 | 0 | 828.0 | 0 | 0 | 0 | 0 |
| 1982 | 0 | 400 | 0 | 1,497.0 | 0 | 0 | 0 | 0 |
| 1983 | 0 | 500 | 0 | 1,259.9 | 0 | 0 | 0 | 0 |
| 1984 | 935.5 | 0 | \$8 | 0 | \$16.4 | \$37.4 | \$136.4 | \$1,330.4 |
| 1985 | 906.1 | 0 | 8 | 0 | 0 | 39.2 | 128.7 | 1,239.8 |
| 1986 | 914.7 | 0 | 8 | 0 | 0 | 41.2 | 121.2 | 1,174.4 |
| 1987 | 916.0 | 0 | 8 | 0 | 0 | 43.3 | 114.2 | 1,109.6 |
| 1988 | 915.9 | 0 | 8 | 0 | 0 | 45.4 | 107.6 | 1,051.8 |
| 1989 | 916.7 | 0 | 8 | 0 | 0 | 47.7 | 101.3 | 1,019.4 |
| 1990 | 917.4 | 0 | 8 | 24.3 | 0 | 50.1 | 95.4 | 992.5 |
| 1991 | 918.0 | 0 | 8 | 18.4 | 0 | 52.6 | 79.7 | 967.7 |
| 1992 | 917.6 | 0 | 8 | 17.7 | 0 | 55.2 | 73.4 | 944.8 |
| 1993 | 918.3 | 0 | 8 | 14.1 | 0 | 58.0 | 68.2 | 923.4 |

[23] The value of gas is undoubtedly higher since the intrinsic value of gas is greater than that of oil (clean, efficient, etc.) and a continuation of gas supply avoids the capital costs of conversion.

[24] Fuel costs are not included. The U.S. will supply its share of fuel used to transport the gas through Canada and that cost is reflected automatically in the benefit calculation.

## EXHIBIT 4.—ALCAN NNEB COMPONENTS—Continued

[Dollar amounts in millions]

| Year | Delivered gas (trillions Btu's) | Field gathering and conditioning | Field operation and maintenance | U.S. transport facilities | U.S. working capital | U.S. operation and maintenance | Other U.S. taxes | U.S. share Canadian costs |
|---|---|---|---|---|---|---|---|---|
| 1994 | 918.6 | 0 | 8 | 0 | 0 | 60.9 | 63.3 | 903.5 |
| 1995 | 918.9 | 0 | 8 | 0 | 0 | 63.9 | 58.5 | 885.0 |
| 1996 | 919.0 | 0 | 8 | 0 | 0 | 67.1 | 54.0 | 868.0 |
| 1997 | 919.6 | 0 | 8 | 0 | 0 | 70.5 | 49.6 | 852.2 |
| 1998 | 920.0 | 0 | 8 | 0 | 0 | 74.0 | 45.5 | 837.6 |
| 1999 | 920.6 | 0 | 8 | 0 | 0 | 77.7 | 41.4 | 825.3 |
| 2000 | 920.5 | 0 | 8 | 0 | 0 | 81.6 | 37.5 | 812.6 |
| 2001 | 920.5 | 0 | 8 | 0 | 0 | 85.7 | 34.5 | 812.8 |
| 2002 | 919.7 | 0 | 8 | 0 | 0 | 89.9 | 30.6 | 799.2 |
| 2003 | 919.4 | 0 | 8 | 0 | 0 | 94.4 | 26.8 | 767.1 |
| 2004 | 919.0 | 0 | 8 | 0 | 0 | 99.2 | 22.8 | 736.5 |
| 2005 | 919.0 | 0 | 8 | 0 | 0 | 104.1 | 19.0 | 707.0 |
| 2006 | 919.0 | 0 | 8 | 0 | 0 | 109.3 | 15.2 | 678.7 |
| 2007 | 919.0 | 0 | 8 | 0 | 0 | 114.8 | 11.5 | 651.6 |
| 2008 | 919.0 | 0 | 8 | 0 | 0 | 120.5 | 7.7 | 625.5 |
| 2009 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2010 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 22,998.0 | 1,444 | 200 | 3,949.4 | 16.4 | 1,7[illegible] | 1,544.0 | 22,516.4 |

## EXHIBIT 5.—EL PASO NNEB COMPONENTS

[Dollar amounts in millions]

| Year | Delivered gas (trillions Btu's) | Field gathering and conditioning | Field operation and maintenance | U.S. transport facilities | U.S. working capital | U.S. operation and maintenance | Other U.S. taxes | U.S. share Canadian costs |
|---|---|---|---|---|---|---|---|---|
| 1977 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1978 | 0 | 0 | 0 | $80 | 0 | 0 | 0 | 0 |
| 1979 | 0 | 0 | 0 | 180 | 0 | 0 | 0 | 0 |
| 1980 | 0 | $200 | 0 | 530 | 0 | 0 | 0 | 0 |
| 1981 | 0 | 344 | 0 | 1,275 | 0 | 0 | 0 | ...... |
| 1982 | 0 | 400 | 0 | 2,375 | 0 | 0 | 0 | 0 |
| 1983 | 0 | 500 | 0 | 1880 | 0 | 0 | 0 | 0 |
| 1984 | 444 | 0 | $4 | 480 | 0 | $130.3 | $125.6 | 0 |
| 1985 | 888 | 0 | 8 | 0 | 0 | 273.6 | 270.8 | 0 |
| 1986 | 888 | 0 | 8 | 0 | 0 | 287.3 | 260.3 | 0 |
| 1987 | 888 | 0 | 8 | 0 | 0 | 301.6 | 249.8 | 0 |
| 1988 | 888 | 0 | 8 | 0 | 0 | 316.7 | 239.3 | 0 |
| 1989 | 888 | 0 | 8 | 0 | 0 | 332.5 | 228.8 | 0 |
| 1990 | 888 | 0 | 8 | 0 | 0 | 349.2 | 218.3 | 0 |
| 1991 | 888 | 0 | 8 | 0 | 0 | 366.6 | 207.8 | 0 |
| 1992 | 888 | 0 | 8 | 0 | 0 | 384.9 | 197.2 | 0 |
| 1993 | 888 | 0 | 8 | 0 | 0 | 404.2 | 186.7 | 0 |
| 1994 | 888 | 0 | 8 | 0 | 0 | 424.4 | 176.2 | 0 |
| 1995 | 888 | 0 | 8 | 0 | 0 | 445.6 | 165.7 | 0 |
| 1996 | 888 | 0 | 8 | 0 | 0 | 467.9 | 155.2 | 0 |
| 1997 | 888 | 0 | 8 | 0 | 0 | 491.3 | 144.7 | 0 |
| 1998 | 888 | 0 | 8 | 0 | 0 | 515.8 | 134.1 | 0 |
| 1999 | 888 | 0 | 8 | 0 | 0 | 541.7 | 123.6 | 0 |
| 2000 | 888 | 0 | 8 | 0 | 0 | 568.7 | 113.1 | 0 |
| 2001 | 888 | 0 | 8 | 0 | 0 | 597.2 | 102.6 | 0 |
| 2002 | 888 | 0 | 8 | 0 | 0 | 627.0 | 92.1 | 0 |
| 2003 | 888 | 0 | 8 | 0 | 0 | 658.4 | 81.6 | 0 |
| 2004 | 888 | 0 | 8 | 0 | 0 | 691.3 | 71.1 | 0 |
| 2005 | 888 | 0 | 8 | 0 | 0 | 725.9 | 60.5 | 0 |
| 2006 | 888 | 0 | 8 | 0 | 0 | 762.2 | 50.0 | 0 |
| 2007 | 888 | 0 | 8 | 0 | 0 | 800.3 | 39.5 | 0 |

EXHIBIT 5.—EL PASO NNEB COMPONENTS—Continued

[Dollar amounts in millions]

| Year | Delivered gas (trillions Btu's) | Field gathering and conditioning | Field operation and maintenance | U.S. transport facilities | U.S. working capital | U.S. operation and maintenance | Other U.S. taxes | U.S. share Canadian costs |
|---|---|---|---|---|---|---|---|---|
| 2008 | 888 | 0 | 8 | 0 | 0 | 840.3 | 29.0 | 0 |
| 2009 | 444 | 0 | 4 | 0 | 0 | 441.2 | 9.2 | 0 |
| 2010 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 22,200 | 1,444 | 200 | 6,800 | 0 | 12,746.2 | 3,732.8 | 0.0 |

EXHIBIT 6.—NNEB COMPARISON

[In billions of 1975 dollars]

| | El Paso [1] | Alcan [1] |
|---|---|---|
| Value of gas | $10.849 | $11.791 |
| Less: | | |
| Field capital costs | 0.873 | 0.873 |
| Transport facilities | 4.074 | 2.334 |
| U.S. working capital | 0 | .008 |
| U.S. O&M (field and system) | .820 | .157 |
| U.S. other taxes | .456 | .222 |
| Canadian cost of service | 0 | 2.431 |
| NNEB | 4.626 | 5.766 |

[1] Based upon 2.4 bcfd input at 1137.8 Btu/cf.

While both projects exhibit the ability to absorb substantial cost overruns without becoming uneconomic, Alcan's ability is greater than that of El Paso. Assuming that the elasticity of cost of service with respect to direct cost overruns is about 0.8, Alcan's direct costs could increase almost 124 percent over the cost overrun case before it would become socially uneconomic; the comparable figure for El Paso is 114 percent.

In conclusion, the economic considerations overwhelmingly favor the Alcan overland pipeline measured against the El Paso LNG transportation system. The cost of service will be significantly less; the net national economic benefits will be significantly higher; the amount of energy delivered will be significantly higher; and the ability to absorb cost overruns is greater.

## CHAPTER V—SAFETY, RELIABILITY AND EXPANSIBILITY

Considerations of safety, reliability and expansibility favor the Alcan overland pipeline system in comparison to the LNG system proposed by El Paso.

The safety record for LNG storage and transportation has been excellent during the past quarter of a century. Nevertheless, LNG facilities present marginally higher risks of a major accident than overland pipelines. An LNG project requires a careful approach to facility siting. The United States may need to rely more upon LNG in the future. However, the use of LNG should be chosen where there is no economically and environmentally feasible alternative.

The greater reliability of the Alcan system should be emphasized. The El Paso system is a multiple-mode system that would be sized and operated at very close capacity and operational tolerances, a factor that tends to decrease reliability. Further, the El Paso pipeline would cross several major geologic faults—the Alaska LNG facility and the California regasification facility would be sited in some of the most seismically active areas in the world. Although the facilities can be designed and constructed to survive structurally a major seismic event, there inevitably would be interruption in service during repair. By contrast, the seismic risk to the Alcan system is very small. It will approach relatively few seismically active areas and will cross no known active faults in Alaska.

Finally, expansibility of capacity also weighs in favor of the Alcan system. The capacity of a properly designed all-pipeline system can be expanded incrementally up to a point simply by the addition of compression at relatively low capital cost. The capacity of an LNG system, on the other hand, must be expanded in large increments that may be excessive in relation to the actual need.

The specific safety and design areas which have been addressed by U.S. and Canadian authorities and to which Alcan must now properly respond as the project moves forward include:

Safety of Design and Operation;

Potential for Service Interruption—Reliability;

Efficiency of Design and Capability of Expansion; and

Monitoring Construction and Joint U.S./Canadian Coordination.

These safety and design issues, involving new technologies for the Alaska gas system, were reviewed by an Interagency Task Force under the lead of the Department of Transportation (DOT), with participation by the Departments of the Interior and Commerce, the Federal Energy Administration, the Energy Research and Development Administration, and the Environmental Protection Agency.

### SAFETY OF DESIGN AND OPERATION

The technical problems in operating a pipeline at high pressures and the transportation of natural gas at chilled temperatures have been carefully considered by government and industry officials. Specific issues include:

High strength pipe metallurgy;

The possibility of frost heave effects on the pipeline in permafrost soils;

The choice of pressure testing methods; and

Development of advanced valve designs.

Final resolution of these technical issues will be needed before there can be site specific approvals of system design and initiation of construction.

*Pipe Metallurgy.—The principal factors that affect safety of the pipeline system are the type, design, physical properties, the metallurgy of the pipe used, and quality control for the pipe.*

Alcan initially proposed to operate its 48-inch system at 1260 psig pressure with the pipeline buried and the gas chilled below 32°F before shipment through permafrost regions. It is probable that Alcan will redesign its system between Whitehorse, Yukon, and Carolina Junction, Alberta, to increase capacity and allow for the economical transportation of Canadian gas from the Mackenzie Delta. The principal alternatives are a 48-inch, 1680 psi system or a 54-inch, 1120 system. In addition, if a 1680 system is installed south of Whitehorse, consideration will be given to installation of a 1680 psi system in Alaska, perhaps with a pipe diameter less than 48-inch. The higher pressure system is generally more economically efficient than lower pressure designs.

To date, the highest pipeline operating pressure has been approximately 1000 psi. From the evidence submitted at the FPC hearings, the DOT and the Safety and Design Task Force tentatively have concluded that the higher operating pressures (1670 to 1680 psi) could be safely achieved with adequately designed pipe. However, further testing and evaluation will be required. The Agreement on Principles between the United States and Canada provides for a jointly conducted testing and evaluation program to determine which system would offer the highest degree of safety, reliability and efficiency. Upon completion of the testing program, the respective regulatory authorities of each country will make a final decision as to which type of system might be installed in each country.

Another issue pertaining to high pressure pipe is whether special "crack arrestors" will be required to stop fracture propagation in the event a fracture should occur. The Safety and Design task force concluded that the fracture toughness properties designed into the pipe specified by the various operators should be sufficient to prevent the initiation of a propagating crack even at arctic temperatures. It therefore concluded that crack arrestors were merely a precaution to ensure that in the remote chance a crack were to initiate, any resulting propagation would be controlled. The task force also reported that with proper design and installation, the arrestors would introduce no problems of corrosion control or stress concentration.

However, if Alcan uses crack arrestors, the particular design and installation plans will be reviewed on a site-specific basis by the DOT to assure that they are consistent with the Federal gas pipeline safety standards.

Alcan plans to use high-strength, grade X–70 pipe. The grade has been rated acceptable in the most recent survey of pipe specifications published by the American Petroleum Institute (API). However, a reference specification for X–70 pipe is not presently incorporated in the Federal gas pipeline safety regulations. Reports of operating experience with X–70 pipe and its approval under liquid pipeline safety standards, as well as in the standards and regulations of many other countries, make it probable that the DOT will incorporate the API X–70 pipe specifications into its regulations before commencement of the construction on the Alaska portion of the system. The economic benefits from the use of X–70 pipe provide an incentive to incorporate it into the design of the Alaska gas system.

*Potential for "Frost Heave".—The problem of frost heave (i.e., the upward movement of a buried pipeline resulting from freezing and thawing conditions), which pipelines can experience when buried in areas of discontinuous permafrost, must be adapted for the particular conditions encountered on a site-specific basis. Depending* *upon soil characteristics, some discontinuous permafrost areas are more subject to frost heave than others. Given the time to finalize the route survey, field testing to determine soil conditions, and engineering design capability, Alcan should be able to solve the frost heave problem satisfactorily although costs for doing so may vary from initial estimates.*

Alcan has stated that it expects to encounter 80 miles of frost-susceptible soil along its right-of-way. It plans to use a passive system which consists of loose fitting insulation and select backfill. This will be supplemented by cycling flowing gas temperatures, thermistor monitoring of the pipeline to detect frost heave problems for corrective action, and periodic patrol and visual inspection based upon accessibility of its right-of-way.

The DOT will review the frost heave site-specific design approach for the Alaska section to assure that the final design will provide the required pipe support, and meet the other pertinent provisions of the Federal gas pipeline safety standards in 49 CFR Part 192. Because frost heave problems occur over a period of time, monitoring of the design, construction, and operation of the Alaska gas transportation system by Alcan and government agencies should detect problem areas early and provide the high level of safety and reliability required.

*Pressure Testing.—Once the pipeline is installed, Federal pipeline safety standards require that pipeline systems be pressure tested before initial operation. Alcan proposes to use a hydrostatic test and preheat the test water to prevent its freezing in the line where buried in permafrost areas. This procedure proved workable on the Alyeska crude oil pipeline. However, the Alyeska pipeline was buried only in areas of thaw-stable material and was designed, from a thermal expansion standpoint, to carry warm oil. The Alcan pipeline, on the other hand, will be buried in varied types of soil conditions and designed to carry chilled gas.*

The Task Force on Safety and Design concluded that "the proposed Alcan procedure for hydrostatic testing with heated water would not be appropriate in sections traversing permafrost or discontinuous permafrost unless stringent control of test water temperatures is maintained and adequate temperature sensing devices are installed adjacent to the buried pipe." That report also concluded that an apprcach similar to the one proposed by Arctic Gas, i.e., a hydrostatic test using a water/methanol freeze-depressant solution at stress levels approaching 100 percent specified minimum-yield strength, provided the best assurance that any defects present in the pipe will be disclosed prior to placing the line in service.

Extensive studies were performed by Arctic Gas on the procedures to be used, the manpower to be expended, and the equipment and costs associated with both air and methanol/water testing. The proposed Arctic Gas test plan included procedures for disposing of the methanol after testing and safeguards to be used in the event of a pipeline test failure. Reports to the DOT confirm that there are very few test failures on newly constructed gas pipelines. In the remote event of failure, environmental concerns can be alleviated through development of a spill containment contingency plan and proper method of methanol disposal. Alcan should utilize hydrostatic testing research data developed by Arctic Gas; such information should be made available to Alcan.

*Valve Design and Performance.—If Alcan constructed a 1260 psi system, it would face few problems with regard to design of values for chilled service. However, if Alcan increases pressure to 1680 psi, either for the Alaska segment of its line alone or for sections in Canada, additional valve design evaluation will be necessary. Valves currently installed in operating pipelines have not had service experience at those higher pressures with chilled gas temperature conditions even though some development and test work has been done at the ranges of pressure which were anticipated for the Arctic Gas and El Paso systems. If higher-pressure service is used, valving plans will be reviewed by DOT on a site-specific basis to assure that the designs are consistent with Federal gas pipeline safety standards.*

*Correlation Between Canadian and U.S. Gas Pipeline Safety Standards.—To assure the overall integrity of the Alaska natural gas transportation system and the continued reliability of service to the U.S., it will be necessary to coordinate specific elements of the Canadian and U.S. gas pipeline safety standards. A review is underway to identify and correlate the various specific features of the Canadian and U.S. standards, and with effective technical liaison between the U.S. and Canadian regulatory agencies, these slightly differing standards should not create any problems. It will be necessary for those regulatory officials monintoring construction of the U.S. pipeline system to be aware of and resolve differences in design, particularly as they relate to acceptable levels of safety and reliability of service.*

*Design and Active Seismic Areas.—The proposed Alcan route encounters relatively few active seismic areas and the risk of damage to the Alcan system from earthquake activity is small. Alcan crosses no known active faults in Alaska. The Denali fault is approximately 30 miles away at its closest point. In Canada, Alcan traverses the Shakwab fault which is large but not likely to be active. Alcan plans to provide for earthquake protection by wide-shallow ditch design and granular backfill to provide support for the pipe to an 8.5 Richter scale, and to install valves at either side of the fault.*

Compressor stations for the Alcan system will incorporate structural design for anticipated earthquake stresses and utilize heavier wall pipe where appropriate.

POTENTIAL FOR SERVICE INTERRUPTION—RELIABILITY

Accessibility of the Alcan route by the Alyeska haul road and existing highways in Alaska and in Canada will facilitate proper maintenance of the pipeline system. In certain tundra areas where conflicts may arise between requirements of the Federal gas pipeline safety standards and the environmental protection rules of Federal or State agencies, trade-offs between environmental considerations and pipeline safety and reliability will need to be carefully weighted in specific instances.

The FPC concluded earlier that each of the three systems originally proposed could be operated with a reliability acceptable to the gas consumers of the United States. The record of pipelines generally shows that their continuity of service is by far the best of any mode of transportation in the United States, and Canadian experience, including experience with the pipelines, in the far north is comparable.

The FPC and the Task Force on Safety and Design also concluded that repair of a pipeline outage on any of the systems as originally proposed would normally be very rapid. Again, the accessibility of the Alcan route to haul roads, work pads, and existing highways would facilitate rapid repair. Special techniques and equipment will be required for repairs in remote tundra areas during the period of summer thaws. Techniques originally planned to be used by Arctic Gas for such repair should be considered by Alcan in its maintenance and repair plans.

EFFICIENCY OF DESIGN AND CAPABILITY OF EXPANSION

It was also suggested in the safety and design report that for economic reasons, Alcan should consider increasing the operating pressure and wall thickness of its 48-inch diameter pipeline in order to allow for more efficient increases in throughput rate for additional reserves which might be committed to the system from either Alaska or Canadian sources.

These physical factors determine the capacity of a gas pipeline:

Diameter of pipe;

Operating pressure; and

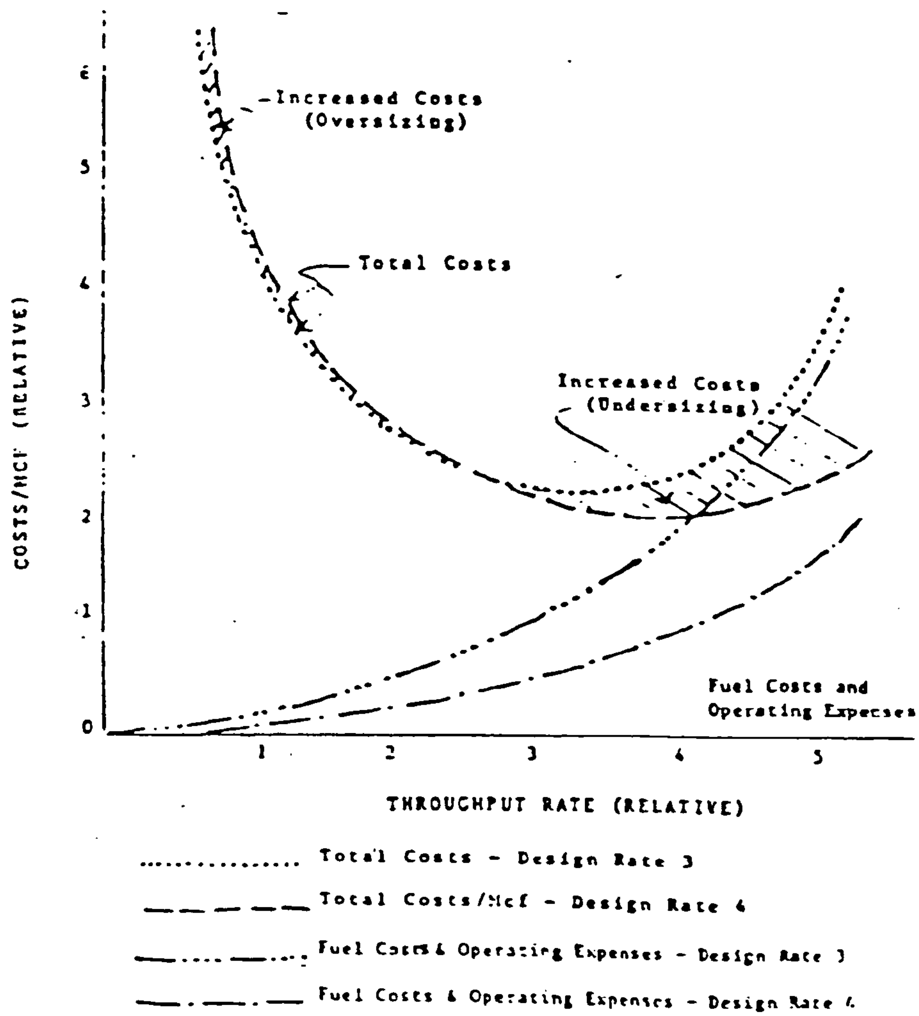
The rate (velocity) at which gas moves through the line.

For any new system the first two items are selected in relation to the expected "throughput" of the gas and are then fixed. Any subsequent increase in the capacity of that pipe requires movement of gas at a higher rate. The velocity of gas is increased by adding compression to the pipeline. Compression requires fuel essentially in proportion to the horsepower added. Thus, as more throughput is required in an existing pipeline, horsepower (capital cost) and fuel use (operating cost) will increase.[25]

The introduction of the additional gas also allows the division of fixed costs by more units of throughput. If the line is operating at less than optimal capacity, the decline in unit fixed costs will be greater than the increase in unit costs for additional horsepower and fuel, and the overall unit cost will decrease. On the other hand, if the pipeline is forced beyond its optimal capacity by addition of yet more compression, the reverse is true: horsepower and fuel increases faster than the declining unit fixed costs, resulting in an increase in overall unit cost of service. Exhibit 4 illustrates the problem.

[25] Horsepower and fuel requirements increase roughly as the difference between the squares of the relative throughputs. Doubling the throughput would require about 4 times as much fuel.

RELATIVE COST vs RELATIVE RATE
DIFFERENT DESIGN CAPACITY



Overall, considering the arctic construction, inflationary impacts, and environmental impacts, the ultimate cost to consumers of providing capacity for increased gas throughput would be much lower if the capacity is provided initially by increasing the diameter or working pressure of the pipe, than if it is provided later by adding compressor horsepower or looping the pipeline.

The routing of the Alcan system provides future access to reserves which might be discovered in the Beaufort Sea or elsewhere on the North Slope. Alcan similarly could transport gas from other areas of Alaska or even from the Gulf of Alaska by means of somewhat longer supply laterals. Further, the Agreement with Canada provides for the use by Canada of the Alcan main line at a throughput up to 1.2 bcfd. Therefore, redesign of the system to enable inexpensive expansibility up to 3.9 to 4.0 bcfd south of Whitehorse, Yukon Territory, is essential.

## CHAPTER VI—ORGANIZATION OF FEDERAL INVOLVEMENT AFTER SYSTEM SELECTION

### INTRODUCTION

A frequently cited problem with construction of the Alyeska pipeline was the multitude of Federal Government agencies that severally prescribed and enforced terms and conditions with only minimal coordination of purpose or effort. Uncoordinated government actions can cause needless construction delays and cost increases. Coordinated Federal oversight of project management and construction would:

Provide coherent and uniform rules, and make them clear to the applicant;

Provide consistent enforcement of the rules; and

Avoid rules and bureaucratic procedures that are merely cumulative and would be sources of delay.

ANGTA provides for creation of a new Federal officer, the Federal Inspector for construction of an Alaska natural gas transportation system. Under Section 7(a)(5) of ANGTA, this Federal Inspector shall—

(A) establish a joint surveillance and monitoring agreement, approved by the President, with the State of Alaska similar to that in effect during construction of the trans-Alaska oil pipeline to monitor the construction of the approved transportation system within the State of Alaska;

(B) monitor compliance with applicable laws and the terms and conditions of any applicable certificate, rights-of-way, permit, lease, or other authorization issued or granted;

(C) monitor actions taken to assure timely completion of construction schedules and the achievement of quality of construction, cost control, safety, and environmental protection objectives and the results obtained therefrom;

(D) have the power to complete, by subpoena if necessary, submission of such information as he deems necessary to carry out his responsibilities; and

(E) keep the President and the Congress currently informed on any significant departures from compliance and issue quarterly reports to the President and the Congress concerning existing or potential failures to meet construction schedules or other factors which may delay the construction and initial operation of the system and the extent to which quality of construction, cost control, safety and environmental protection objectives have been achieved.

While the Federal Inspector can "monitor" the enforcement and compliance actions of the various Federal agencies, he does not have any specific enforcement powers. A coordinated regulatory approach will be elusive unless the Federal Inspector has the necessary supervisory authority at the field level over enforcement of terms and conditions to ensure that coordination occurs.

Therefore, as set forth in the Presidential decision, the President will submit to Congress upon approval of the *Decision* a limited executive reorganization plan for the very specific purpose of transferring to the Federal Inspector field-level supervisory authority over the enforcement of stipulations and terms and conditions from those Federal agencies having statutory responsibilities over various aspects of an Alaska natural gas transportation system. This coordinated field level authority over compliance and enforcement activities of the respective Federal agencies is essential to avoid project delays and minimize cost overruns.

However, the Federal Inspector will be subject to the ultimate policy direction and supervision of an Executive Policy Board, made up of the Secretaries of Interior, Energy, and Transportation, the Administrator of the Environmental Protection Agency and the Chief of the Army Corps of Engineers. Furthermore, all Federal agencies will retain their existing authorities, pursuant to section 9(a) of ANGTA, to issue original certificates, permits, rights-of-way and other authorizations, and to prescribe any appropriate stipulations and terms and conditions to such authorizations that are permissible under existing law. Finally, the Agency Authorized Officers, who will exercise the delegated authorities of their respective agencies, will directly enforce the stipulations and terms and conditions—subject to the field-level supervisory direction of the Federal Inspector.

With these organizational proposals, and with the general terms and conditions set forth in the *Decision,* the Federal Government will have an expanded role in the oversight of project management and construction. The oversight authority conferred by the terms and conditions set forth in the *Decision* will be far more comprehensive than the limited Federal monitoring effort over Alyeska's project management. If these general terms and conditions are effectively enforced, most of the management abuses associated with the Alyeska project should not recur. The general terms and conditions, however, do not hold the successful applicant to any specific management approach, but merely provide certain minimum standards for cost and quality control and timely completion of construction, which reflect the collective experience and knowledge gained by the various Federal agencies from involvement with the Alyeska project.

## THE ORGANIZATION OF FEDERAL INVOLVEMENT WITH THE ALCAN PROJECT

As noted above, the Federal Inspector will have the field-level supervisory authority over the Agency Authorized Officers who will be assigned on a full-time basis to administer the authorities of their respective agencies over various aspects of the Alcan project. The Federal Inspector and the Agency Authorized Officers will constitute an Alaskan Natural Gas Pipeline Office.[26] This Office will consist of administrative and field inspection and monitoring staff working under the direction of the Federal Inspector. The Executive Policy Board will approve the level of staff support, and determine Agency Authorized Officer participation in providing such staff support to the Federal Inspector.

Essentially, the organization of Federal involvement with the Alcan project has three elements:

1. *The Federal Inspector.*—The Federal Inspector will be a Presidential appointee confirmed by the Senate and is an officer independent of other existing Federal agencies. In addition to his statutory duties under section 7(a)(5), the Federal Inspector will have supervisory authority at the field level over enforcement of terms and conditions, and will otherwise coordinate Federal involvement with the pipeline operator during the design and construction phases of the project. The Federal Inspector is designed to be the principal point of contact with the pipeline owners, the contractors, State agencies, and Canadian entities on matters pertaining to Federal oversight of the project. As chairman of the Executive Policy Board, he should be the executor of its policy decisions. The Federal Inspector also has the power to compel information by subpoena and to issue quarterly reports to the President and Congress concerning existing or potential failures to meet construction schedules and other matters.

2. *The Executive Policy Board.*—Presidential supervision over the Federal Inspector will be delegated to an Executive Policy Board. The Board would be made up of the Secretaries of the Interior, Energy, Transportation, the Administrator of the Environmental Protection Agency, and the Chief of the Army Corps of Engineers, or their Deputies (or senior officers who have been delegated authority over gas pipeline matters). The Federal Inspector shall serve as the non-voting chairman of the Board.

The Board will provide policy guidance *through* the Federal Inspector to the Agency Authorized Officers and will be paramount in all policy matters. It will also act as an appellate body to resolve any differences between the agencies and the Federal Inspector, including differences that may arise when the Federal Inspector overrules an enforcement action of an Agency Authorized Officer. In such cases, the Board shall expeditiously resolve any appeal within a specified time period. Otherwise, the Board shall confine itself to policymaking matters, and the Federal Inspector will be the conduit of the Board in carrying out policy.

[26] The Office should be located in Alaska, at least for the construction phase of the project, and later in reduced form for the operational phase. It is probable that preconstruction planning and design will necessitate an Alaska-based pipeline office (e.g., to coordinate site-specific terms and conditions) even though the size of the Washington, D.C.-based staff will be larger in the earlier phases of the project.

3. *The Agency Authorized Officers.*—These officers will represent and exercise the internally delegated authorities of their respective agencies in matters pertaining to the project. Although these authorities can be exercised only by the respective Agency Authorized Officers, they will be subject to supervision of the Federal Inspector at the field level, and receive policy direction from the Executive Policy Board through the Federal Inspector on enforcement matters.

The Agency Authorized Officers should have no other administrative duties that would require less than full attention to the project, unless the Executive Policy Board consents to waive this requirement in a particular case. It is hoped that the use of Agency Authorized Officers to represent the various agencies will minimize coordination problems between the project applicant and the Federal Government.

### IMPLEMENTATION OF ORGANIZATIONAL PLAN

The proposed transfer of field-level supervisory authority to the Federal Inspector should be submitted for approval by Congress in a government reorganization plan, rather than implemented by executive order. This plan will propose a limited, single-purpose transfer of field-level supervisory authority over enforcement of terms and conditions for the duration of the preconstruction and construction phases of the Alcan project. No other transfer of existing authority, or transfer of any coordination function, will be proposed in the reorganization plan.

To avoid the possible overlap with Congressional action on the Presidential decision itself, the reorganization plan will not be submitted to Congress until that decision has been approved. Congress would then have 60 legislative days in which to consider the merits of the plan under the special parliamentary procedures provided by the Reorganization Act of 1977, 5 USC 901 et seq.

The President can immediately issue an executive order creating the Executive Policy Board and by his power pursuant to Section 301 of Title 3, delegate the necessary authority to the Board to carry out its functions. The Board can then make certain initial administrative decisions regarding the Office of Federal Inspector—e.g., the level of staff support for the Federal Inspector, and the possible use of the Army Corps of Engineers for such staff support. In the interim, the Federal Inspector can immediately exercise his responsibilities under existing ANGTA authority to "monitor" compliance by Alcan with applicable laws and authorizations.

### COORDINATION WITH THE STATES

In addition to the duty of organizing Federal involvement, the Federal Inspector has the substantial responsibility under ANGTA to establish a joint surveillance and monitoring agreement with the State of Alaska and other affected States. The strengthened field level supervisory authority proposed for the Federal Inspector will be of great assistance in the performance of this statutory responsibility.

The Alcan system will pass through hundreds of miles of land owned by the States, particularly by the State of Alaska. Officials of the State of Alaska have previously declared that the State will issue a right-of-way lease to the gas pipeline for crossing these lands, regardless of which project is approved, and have indicated that environmental terms and conditions will be part of this lease.

The States and the Federal Government share responsibility to ensure that lands, water and wildlife are not unnecessarily disturbed by the gas pipeline and that where disturbed, maximum restoration is carried out. The Federal Inspector and Agency Authorized Officers will therefore work with the State of Alaska and with other States in a cooperative fashion both for the protection of the environment and for the expeditious construction of the pipeline. The terms and conditions and stipulations which pertain to State and Federal lands should be as similar as possible. A reasonable accommodation of State and Federal interests is expected with the Federal Government having primary responsibility where the pipeline crosses Federal land and private lands, and with the State Governments having primary responsibility where the pipeline crosses State lands. Cooperative agreements based on these principles have been successful in the recent past, and should be the point of departure for further strengthening the Federal and State cooperation during construction of the gas pipeline.

## CHAPTER VII—IMPACT ON COMPETITION IN THE NATURAL GAS INDUSTRY

The antitrust and competitive impact effects of an Alaskan natural gas system have been thoroughly studied by the Federal Power Commission and by the Justice Department under Sections 6 and 19 of the Alaska Natural Gas Transportation Act of 1976. Under section 19, the Attorney General prepared and submitted to Congress on July 14, 1977, a detailed analysis of potential antitrust issues and problems. Under Section 6, the Attorney General submitted that same report to the Alaskan Natural Gas Task Force, along with a commentary on the FPC's findings with respect to competitive impact. In addition, the Justice Department submitted a letter on August 9, 1977, which elaborated its views concerning possible participation by the gas producers in financing the transportation system. A copy of the letter is appended to the end of this Chapter.

Based on these studies, it can be concluded that the Alcan project will have no harmful effect on regional or national competition in the natural gas industry, and that any potential of competitive abuse can be cured by proper federal regulation. In addition, consistent with the Administration's antitrust objectives, producers of Alaskan gas could participate in financing this expensive transportation system through guaranteeing some portion of the project debt.

### GAS TRANSMISSION AND DISTRIBUTION INDUSTRY

The Federal Power Commission and the Justice Department agreed that certification of a transportation system for Alaskan gas will *not* have a significant impact upon competifion in the natural gas transportation and distribution industries.

Based on statistics presented in the Justice Department's Report to Congress, the American sponsors of the Alcan project, including PGT, PGE and the Northern Border companies, transport aproximately 40 percent of all the interstate natural gas shipped in the U.S. However, in an industry as heavily regulated as natural gas, indices of concentration tend to overstate the potential for anticompetitive behavior. In the presence of effective regulation, the actual prospect of anticompetitive behavior is minimized, and there is only a small risk that the Alcan sponsoring companies could control national or regional gas markets.

### GAS PRODUCERS

Alcan has no oil companies or subsidiaries of oil companies among its sponsors. This fact in itself sharply reduces potential antitrust concerns.

Nevertheless, since elsewhere in this Report it is urged that the gas producers participate in financing this project, it is necessary to examine the competitive considerations associated with producer participation. The Attorney General concluded that "present Federal Power Commission regulation appears to preclude an opportunity for competitive abuse by the gas producers." However, the Department warned that if wellhead prices were decontrolled or substantially relaxed, some opportunity might arise for producers, if they owned or controlled the transportation system, to transfer profits from the regulated transportation operation to their unregulated upstream production operations.

The Department of Justice indicated that its concern about producer ownership or control of the pipeline *does not preclude producer participation in financing the system*. For example, consistent with antitrust objectives, producers could be involved in guaranteeing a portion of the project's initial debt or cost overrun debt. To assure antitrust insulation, any producer role in the management of the transportation system prior to its becoming operational should be the minimum necessary to protect the producers' investment interest but in any event should not permit producers to engage in anticompetitive conduct. In addition, producer debt guarantees should terminate upon completion of the project and commencement of the tariff. Finally, the Federal Power Commission should utilize its approval power over 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 abuses of competition.

Thus, as is urged elsewhere in this report, gas producers could guarantee portions of the project debt consistent with this Administration's antitrust objectives.

* * * * * * *

Overall, we conclude that the potential for anticompetitive abuse by either the gas transmission and distribution industry or the gas producers (to the extent they might participate in guaranteeing project debt) is small, especially under a continuing system of price regulation. Any potential competitive problems can be guarded against through (1) imposing proper conditions in the license to construct the transportation system (including the non-discriminatory conditions under section 13(a) of the Act); (2) monitoring gas purchase contracts between gas producers and gas transmission companies; (3) requiring the disclosure of any collateral agreements between producers and transmission companies; (4) requiring government scrutiny and approval of any plans for gas reallocation or displacement, and government monitoring of any industry discussions to derive such plans; and (5) imposing regulatory sanctions in any specific cases of abuse that may arise.

EXHIBIT

DEPARTMENT OF JUSTICE,
Washington, DC, August 9, 1977.

Mr. LESLIE J. GOLDMAN,
*Assistant Administrator, Energy Resources Development, The White House, Washington, DC.*

DEAR MR. GOLDMAN: The Attorney General submitted his Reports on the competitive aspects of the Alaska natural gas transportation system to the President and to the Congress on July 14, 1977. One of the conclusions drawn in those Reports was that producers of substantial amounts of natural gas should not be permitted to own any portion of or participate in any manner in the selected Alaska natural gas transportation system.

The Department has been requested by the Alaska Natural Gas Task Force to consider whether this recommendation precludes the participation of the Alaskan natural gas producers in the financing of the selected project. We have been requested to focus our attention on the two routes still under active consideration—the all-pipeline route proposed by Alcan Pipeline Company and the pipeline-LNG route proposed by El Paso Alaska Company.

The Department's recommendation concerning gas producer ownership and participation was based on the premise that such ownership or participation under a regime of deregulated or relaxed wellhead price regulation could lead to the evasion of effective pipeline regulation and create the opportunity for the earning of monopoly profits through anticompetitive activity. Despite the continuation of wellhead price regulation and the present lack of gas producer ownership or participation in either the Alcan or El Paso projects, we continue to express our concerns on this important issue, since the long term status of wellhead price regulation appears uncertain and it is not now clear who will be the ultimate owners of these projects. However, our concern about gas producer ownership of the projects does not mean that there would necessarily be antitrust objections to participation in project financing on the part of Alaskan gas producers.

From consultation with other members of the Alaskan Natural Gas Task Force, we understand that gas producer participation in the financing of the selected project may be essential to the success of the project. We believe, therefore, that consistent with our recommendations producers could be involved in the guarantee of a portion of the project debt. We view this guarantee as consistent with our recommendations so long as the gas producers would not be equity members of the sponsoring consortium, would not have any voting power, would not have any role in the management or operations of the transportation system once the system would become operational and would be obliged to terminate their guarantor roles upon completion of the project and the tariff's going into effect. Any role in the management of the transportation system prior to the system becoming operational would be minimal and consistent with the size of the guarantee and would not lead to the types of anticompetitive conduct indicated in the Attorney General's Report on the Alaskan natural gas transportation system and in this letter.

Although not opposed to some financial backstopping under these conditions, we reiterate our opposition to any type of financial participation by producers that would enable them to engage in any form of anticompetitive conduct, such as the restriction of pipeline throughput, the denial of access to nonowners, or the resistance or denial of future expansion of pipeline capacity.

The Department recognizes that if the gas producers were to act as debt guarantors they would have the right to request conditions to protect their financial involvement. The Department would not oppose conditions to this effect so long as the conditions would not give rise to the potential for competitive abuse, including the power to veto procompetitive policies, referred to above. In this regard, we would expect to urge the Federal Power Commission, or its successor agency, at the appropriate time, to utilize its approval power over gas purchase contracts and, more generally, over project financing plans, to ensure that producer-imposed conditions do not conflict with the antitrust objectives outlined in the Attorney General's Reports.

In addition, as a further safeguard, the Department suggests that it review all the terms and conditions of any financial guarantee of a portion of the project debt negotiated with the Alaskan gas producers. You are assured of our willingness to assist in exploring and developing an appropriate method of gas producer financial participation in an Alaskan natural gas transportation system that will not subvert the competitive spirit and intent of the recommendations contained in our Reports.

Sincerely yours,

HUGH P. MORRISON, Jr.,
*Acting Assistant Attorney General,*
*Antitrust Division.*

## CHAPTER VIII—NATIONAL SECURITY

The Department of Defense (DOD) provided a study on the national security implications of the proposed Alaska gas transportation systems both to the Department of the Interior, for its report required by the Trans-Alaska (Oil) Pipeline Act (P.L. 93–153),[27] and to the Federal Power Commission (FPC) for its use in evaluating the proposals. The conclusions of the DOD study were that analysis of military factors alone would not indicate an overriding preference for one route over another.

A DOD representative testified on the study before the FPC and was cross-examined by representatives of both El Paso and

[27] "*Alaska Natural Gas Transportation Systems, A Report to the Congress Pursuant to P.L. 93–153,*" U.S. Department of the Interior, December, 1976.

Arctic Gas, after direct examination by the FPC's Administrative Law Judge Litt and a staff attorney. As reported by Judge Litt:

> * * * the evidence shows each system has its advantages and disadvantages. El Paso's entire pipeline portion of its system is under U.S. control, and thus defense strategy may be facilitated. However, El Paso's project tends to concentrate potential targets, like its liquefaction and regasification plants, whose destruction would present major, long-term outage problems. Similarly, both the oil and gas pipelines would be susceptible to concentrated attack or sabotage on the Yukon River Bridge. Arctic Gas and Alcan, while not concentrating vulnerable facilities at single locations or subjecting their systems to interdiction at sea, suffer somewhat from the length and location of their pipelines. Moreover, these projects must rely on Canadian security forces for defense over much of their pipeline lengths.[28]

The consensus was that each of the proposed systems has some national security problems which are peculiar to that system, and that the extremely modest danger due to hostile acts is of some concern, whether such acts are in wartime or are acts of sabotage. However, such danger was considered to be far less likely to disrupt pipeline operations than system failures of a purely natural or mechanical nature.

DOD also submitted a report to the President on July 1 commenting on the national security implications of the FPC's *Recommendation to the President.*[29] In that report, DOD reiterated its conclusion that there is no overriding preference for one route over another when analysis is based on military factors alone. However, the report pointed out that dependence on imported oil presents a grave danger to the national security, and stressed that completion of a transportation system for delivery of Alaska North Slope natural gas to the contiguous 48-states must be considered an important national security objective.

With the Alcan joint project with Canada, we believe Canada will have a major interest in maintaining a uninterrupted flow of gas through the pipeline as well as a treaty obligation to do so under the recently ratified pipeline treaty. First, the Canadian companies which will be the owners of the Pipeline in Canada will have a substantial investment which they will want to have protected. Canadian investors would be adversely affected by any interruption in throughput. Second, remote communities in both the Yukon Territory and the western provinces will be served by the Pipeline, and any interruption in flow will directly affect availability of gas to those communities. Finally, a much larger number of Canadian gas consumers will have a direct interest in uninterrupted throughput when the Dempster Line comes into service from the Mackenzie Delta. The Canadians expect the Dempster Line to be built within several years of initiation of service on the main line.

[28] *Initial Decision on Proposed Alaska Natural Gas Transportation Systems*, Federal Power Commission, February 1, 1977, p. 411.
[29] *Recommendation to the President*, Federal Power Commission, May 1, 1977.

Provision for access to the Mackenzie Delta reserves will have beneficial effects on the national security of both countries due to decreased dependence on imported oil. Canadian oil import requirements will be directly reduced by availability of gas to Canadian consumers. Access to frontier gas reserves will allow Canada to fulfill its current gas export commitments, preventing an increased degree of U.S. oil import dependence due to curtailment of Canadian gas supplies. Attaching Canadian frontier gas and providing a stimulus to the Canadian oil and gas producing industry may ultimately allow some increase in the level of Canadian gas exports, which would allow even further reduction in oil import dependence.

## CHAPTER IX—THE WESTERN LEG

### THE AUTHORIZATION OF FACILITIES

There are two basic methods for delivering Alaskan natural gas to the West Coast. The first method is to construct a "Western Leg" to the Alcan system by constructing a new pipeline and some looping in Canada from Caroline Junction to Kingsgate, and by increasing the capacity of the existing Pacific Gas Transmission (PGT) and Pacific Gas and Electric (PG&E) pipeline, also through looping. A fully looped system would cost about $770 million (1975 dollars).

The second method is to deliver the gas to the West by "displacement." The Northern Border section of the Alcan project to Chicago could be sized to deliver all Alaska gas to the Midwest. Natural gas from West Texas and New Mexico that otherwise would flow to the Midwest could then be diverted to the West Coast through the El Paso, Transwestern and Nothwest pipeline systems.

As set forth in the Presidential Decision, construction of a Western Leg will be authorized for direct delivery of Alaskan gas to the West Coast. See page 20 of the *Decision*. The Western Leg facilities proposed by the sponsors in the FPC hearings (i.e., the "1580 Design") will be authorized for "construction and initial operation." All such facilities will be entitled to the special mandatory certification and expediting procedures provided by ANGTA.

However, the facilities proposed in the "1580 Design" will be subject to a final review and possible adjustment prior to final certification by the FPC. As in the case of the Northern Border system, the Secretary of Energy shall determine at the time of certification whether the facilities proposed in the "1580 Design" are larger or smaller than necessary to handle the contracted supplies of Alaskan gas and Canadian exports and whether "preconstruction" is necessary to accommodate short-term excess deliveries of Canadian gas from Alberta. The "1580 Design" facilities would be needed to handle exports from Canada continuing beyond current contract expiration dates or if new gas supplies from Alaska are developed. Furthermore, complete delivery by displacement would not be feasible if Mexican gas becomes available and the 30 inch gas pipeline that is part of the El Paso system between Texas and California is converted to an oil pipeline for use in the Sohio project to transport surplus Alaskan crude oil.

At the time of certification, however, when there will likely be better information upon which to project future gas supplies, the "1580 Design" may prove not to be the appropriate size. Therefore, the *Decision* does not make an irrevocable commitment to construct new capacity that is either too small or too large for the projected needs. Prior to final certification of a Western Leg, the Secretary of Energy shall make the precise determination of facility size and volume to account for material changes in the facts, if any, since the Presidential decision. The Western Leg may also be utilized in connection with short-term deliveries from Canada.

The Western Leg facilities required for direct delivery will depend on several estimates—the estimated Western share of Alaskan gas, the estimated volume of Canadian exports, the amounts of Mexican gas, and the abandonment of the El Paso gas line in favor of the Sohio oil transport system. These estimates provide the basis for the decision to authorize the Western Leg.

### The Western share of Alaskan gas

The proportion of natural gas that is distributed to a particular region of the country is ordinarily determined by private contract between the producers, on the one hand, and the purchasers which are usually interstate pipeline or local distribution companies, on the other.

There is no reason to change these rules for Alaskan gas. A region of the country that is arbitrarily and inequitably deprived of its share of Alaskan gas will have the opportunity to seek relief from the FPC. But, in the absence of such discrimination, regional distribution of Alaska gas will be made by the usual means of private agreement.

Since contracts for the purchase and sale of Alaska North Slope gas have not yet been executed, it cannot now be determined with precision how much of that gas will eventually be destined for the western states. However, in the absence of sales contracts, it is reasonable to assume that 30 percent of the Alaskan gas will be purchased by parties served by the Western Leg. It is also assumed that deliveries of Alaskan gas to the lower 48 States will begin at 2 bcfd in 1983 and increase to about 2.4 bcfd within a few years. For purposes of this analysis, then approximately 700 mmcfd will be considered the maximum Western share of Alaskan gas through this period.

### Increased and accelerated Canadian exports

In its July 4th decision authorizing the Alcan proposal, the Canadian National Energy Board (NEB) assured the continuation of current Canadian supplies to the West. It rejected outright any suggestion that existing Canadian agreements to export gas to U.S. markets not be honored. The NEB also concluded that gas production from the established fields of Alberta and British Columbia would exceed total demand, including exports, by as much as 400 bcf in 1978, and had created a temporary excess supply.

It proposed that the current Canadian "gas bubble" be sold to export customers, either as "predeliveries" on contract volumes that would otherwise be delivered in the 1984–90 periods, or under an "ironclad" guarantee that it would be replaced later by Alaskan gas delivered in Canada. And finally, in order to assure the delivery of these additional volumes, it recommended the "preconstruction" of that portion of the total system that would be located in southern Canada.[30]

The recently signed Agreement on Principles makes it even more likely that there will be an increase or acceleration of gas exports from Alberta. By providing Canada with access to frontier gas reserves in the Mackenzie Delta, the Alcan proposal stimulates the gas industry in Canada, and enhances the availability of Canadian supplies for absolute increases in exports to the United States.

The following sections set forth the analysis of the capacity available in existing pipeline systems to transport these additional volumes of Alaskan or Canadian gas directly or by displacement to the Western States.

## ESTIMATED EXCESS PIPELINE CAPACITY IN EXISTING SYSTEMS

### Existing facilities of the Western States

At the present time, the West is provided with most of its natural gas via interstate pipelines from two major producing areas—the established gas fields of the southwestern United States, particularly in the Permian and San Juan Basins, and the Alberta and British Columbia reserves in Canada. For purposes of this analysis, there are two principal interestate pipeline systems that should be considered in evaluating the capacity requirements of Western States. They are: the Pacific Gas Transmission and Pacific Gas & Electric systems from Kingsgate, B.C. to Antioch, California, which supply Washington, Oregon and Idaho markets, as well as California, with Canadian gas, and (2) the El Paso and Transwestern systems in the Southwest (referred to collectively hereafter as the Southwest pipeline system), which deliver gas from the Permian and San Juan Basins to California, Arizona and New Mexico. As will be seen below, the full share of Alaskan gas plus additional Canadian supplies could not be delivered directly by the PGT and PG&E systems for at least several years and in the interim might well use up and exceed the capacities of the El Paso and Transwestern systems that would be used for displacement.

### Direct delivery

As noted, the Western Leg proposal would amount principally to looping of the existing pipeline facilities from Alberta to California. The existing system could not itself be utilized for direct deliveries of any Alaskan or additional Canadian gas because it is now being utilized to capacity and will be until at least later 1985.

There are four principal contracts pursuant to which Canadian gas is now delivered via the PGT and PG&E systems directly to California, their volumes and the expected expiration dates are as follows:

| Authorized average daily volume (in mcfd): | Expiration date |
|---|---|
| 184.9 | 10–31–85 |

[30] See NEB, Reasons for Decisions: Northern Pipelines, Vol. 1, pp. 1–69 to 1–83, 1–161, June 1977.

| | Expiration date |
|---|---|
| 419.9 | 10–31–86 |
| 205.0 | 10–31–89 |
| 213.0 | 10–31–93 |

Thus, even if none of these contracts is renewed—the likelihood of which is reduced as a result of the Agreement on Principles—direct delivery of substantial volumes in existing facilities will be impossible for the first three or four years of an Alaskan gas transportation system.

Displacement

Under the "displacement" option, the Western share of Alaskan gas would not be directly delivered to the West but moved there indirectly through exchange arrangements with customers of the Northern border system.

In order to carry out the displacement scheme, the capacity of the Northern Border system would have to be such as to accomplish the direct delivery of both the East's and West's share of North Slope gas. Full displacement would require either that the proposed 42-inch Northern Border line south of Empress, Alberta, be fully-powered or that a 48-inch line be constructed over this segment to carry the same volume of gas, at an additional capital cost but with the flexibility to increase capacity.

On the surface, displacement appears to be the most cost effective method. The $770 million (in 1975 dollars) cost of a fully looped Western Leg could be avoided. Increasing the capacity of the Northern Border system would be much less capital intensive; $258 million for fully powering the 42-inch Northern Border System, and $404 million for increasing the pipe diameter to 48-inch. In either case the cost of service for the displacement plan would be about $50 million per year less than direct delivery. However, there are several reasons why displacement is not a desirable long term method in this situation.

(a) Any displacement plan would consume more energy than direct delivery to the West. The West's Alaska gas essentially would move east to Chicago and then back west from the Permian or San Juan basins. By contrast, the looping of the PGT and PG&E systems would increase the overall fuel efficiency for those systems. The difference is about 25 bcf of gas per year, worth $68 million at $2.60 per mmbtu.

(b) Use of displacement to transport all of the West's Alaskan gas would create capacity constraints on the existing El Paso and Transwestern lines if:

One El Paso 30-inch line is converted to an oil line by the Sohio Project;

Substantial volumes of Mexican gas become available for transportation to the West Coast;

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

The Algeria II LNG project is completed on schedule.

For purposes of analysis, all four of these conditions should be regarded as reasonably likely to occur.

While the Federal Government has not specifically endorsed the Sohio Project, it has endorsed generally the need for the expeditious construction of a pipeline to transport surplus Alaskan crude oil from the West Coast to refining markets east of the Rocky Mountains.[31] Such a system is needed to provide economic and efficient transportation of Alaska North Slope oil to markets in the U.S. The conversion of the El Paso pipeline by the Sohio Project, which is assumed in the present analysis, will result in a substantial decrease in overall capacity of the Southwest gas pipeline system.

Recent events have given cause for considerable optimism about increased exports from Mexico which would enter through the Southwestern and El Paso system. Petroleos Mexicanos (Pemex), the government-controlled oil and gas monopoly in Mexico, has recently expressed its intention to construct a 48-inch, 850-mile pipeline from the Reforma fields in Chiapas and Tabasco to the U.S. border near McAllen, Texas. Pemex expects initially to deliver 1 bcfd to the U.S. upon completion of the pipeline (probably not before 1980), and to increase the flow to 2 bcfd by about 1982. On August 3, 1977, Pemex and six U.S. companies signed a memorandum evidencing their intention to enter into supplier-purchaser relationships for 6 years, renewable for another 6-year term if the purchasers meet the best tender Pemex may have for the gas at the end of the first term.

Notwithstanding several remaining uncertainties, it now appears likely that the Mexican Project will soon become a significant new source of gas supply in the Southwest. Between El Paso and transwestern, the West could reasonably expect to receive about 220 mmcfd of Mexican gas by 1980 and a total of 440 mmcfd beginning in 1982.

As discussed above and throughout this *Decision* and *Report*, the Alcan system will offer the potential for accelerated delivery of Canadian exports under existing contracts; it will also enhance the overall availability of Canadian gas for absolute increases in exports. Since these additional volumes of Canadian gas could not be delivered directly in the PGT and PG&E systems, as noted above, they would also have to be displaced through the El Paso and Southweastern systems for delivery to the West.

Finally, the Algeria II project, El Paso's application for which is pending before the FPC, would deliver up to 325 mmcfd of regasified LNG from the Texas Gulf Cost to the Southwest by as early as 1983 and could deliver a total of 650 mmcfd by the following year.

Under these conditions, delivery of Alaskan gas through the Northern Border system for displacement to the West would preempt all the excess capacity now available in the existing Southwest pipeline system from the Permian and San Juan Basins. Any substantial new supplies from the deep Permian formations—or increased supplies from coal gasification projects—would compound the problem.

Indeed, under optimistic assumptions about future gas supplies to the West and the existing capacity to California which would be

[31] See Executive Office of the President, The National *Energy Plan*, April 29, 1977, p. 65.

utilized, there is a serious risk of capacity shortage for the years 1983–87. This shortage can be determined from the data set forth in Exhibit 1.

EXHIBIT 1

| | 1981 | 1982 | 1983 | 1984 | 1985 | 1986 | 1987 |
|---|---|---|---|---|---|---|---|
| Capacity (mmcfd): | | | | | | | |
| El Paso (after abandonment) | 3,274 | 3,272 | 3,274 | 3,274 | 3,274 | 3,274 | 3,274 |
| Transwestern | 785 | 785 | 785 | 785 | 785 | 785 | 785 |
| Total capacity | 4,059 | 4,059 | 4,059 | 4,059 | 4,059 | 4,059 | 4,059 |
| Supply (mmcfd): | | | | | | | |
| Permian Basin | 1,551 | 1,448 | 1,358 | 1,271 | 1,190 | 1,114 | 1,042 |
| San Juan Basin | 1,253 | 1,247 | 1,209 | 1,176 | 1,144 | 1,113 | 1,083 |
| Canadian short-term (by displacement) | 221 | 167 | 112 | 56 | — | — | — |
| Mexican | 220 | 440 | 440 | 440 | 440 | 440 | 440 |
| Algeria II LNG | — | — | 325 | 650 | 650 | 650 | 650 |
| Coal gas | — | — | — | — | 70 | 140 | 280 |
| Total supply | 3,245 | 3,302 | 3,444 | 3,593 | 3,494 | 3,457 | 3,495 |
| Excess capacity | 814 | 757 | 615 | 466 | 565 | 602 | 564 |
| Less Alaskan gas by displacement | — | — | 700 | 700 | 700 | [1]522 | [1]120 |
| Capacity excess (shortage) | 954 | 757 | (85) | (234) | (135) | 80 | 444 |

[1] Assumes that existing Canadian contracts will not be renewed.

The Exhibit indicates that without a Western Leg, a displacement scheme capacity shortage could exist in 1983–85 and would be uncomfortably close in 1986. If current Canadian supply contracts are renewed, as it is hoped they will be, a capacity shortage could exist in 1983 and later years as well.

Finally, it should be noted that full utilization of the Northern Border system for a displacement scheme would preclude the ability to expand the Northern Border system at a low capital cost for additional deliveries to the East if more Alaska gas becomes available.

The Nation's gas delivery system must have the overall flexibility to make a rapid and economic response to many variables—the level of future exports from Mexico, the level of future exports from Canada, the rate at which new supplies of Alaskan gas can become available, and the rate at which LNG and coal gasification projects are developed. Therefore, to ensure sufficient capacity for future supplies to California and other Western States, provision should be made for direct delivery of Alaska gas to the West.

## SIZE AND VOLUME OF A WESTERN LEG

The approved facilities for the Western Leg are embodied in the so-called "1580 Design." It would require a 36-inch, 176-mile pipeline, to be constructed by the Alberta Gas Trunkline Ltd. (AGT), from James River Junction in Alberta to Coleman on the British Columbia border, where it would connect with the existing Alberta Natural Gas Company Ltd. (ANG) line in British Columbia. One hundred and five miles of the existing ANG line, from Coleman to Kingsgate on the U.S. border, would be looped with 36-inch pipe. In the U.S., 612 miles of the PGT line from the Canadian border to Malin, Oregon, and 297 miles of the PG&E line from Malin to Antioch, California, would also be looped with 36-inch pipe. No new compression would have to be added to the existing systems.

With this project, 659 mmcfd of North Slope gas could be delivered directly to the western U.S., which is roughly the total expected volume of Alaskan gas delivered to the West. PGT intends to deliver 22 mmcfd of this amount to Northwest Pipeline Company for distribution in the Pacific Northwest, and the remainder would be delivered to California, where 200 mmcfd would be distributed by PG&E in the North and 437 mmcfd would be distributed by the Southern California Gas Company in the South. Any share of Alaskan gas or additional Canadian gas greater than 659 mmcfd would not require a new facility but could readily be delivered to the West by displacement. There would easily be sufficient capacity in the Southwest system to absorb this relatively small volume of Western gas.

## CONCLUSION

The evidence clearly suggests that the natural gas pipeline capacity available at present will not be adequate to accommodate both the Sohio Project and the movement of Alaskan gas to the West in the mid-1980's and perhaps beyond. While this conclusion is based on optimistic supply projections, it nevertheless is a significant probability on the basis of which a Western Leg Facility should be planned.

There is some risk in authorizing a Western Leg that it or other existing pipeline systems to the West could at some time become somewhat underutilized, perhaps resulting in some increase in per unit costs to gas consumers. But the consequences of not authorizing a Western Leg are even greater. Not only could failure to build a Western Leg under the most reasonable supply projections cause higher direct costs to the consumer, but it could also greatly reduce the West's flexibility to receive new gas supplies if and when they develop in the future. Indeed, whether gas supplies in addition to what are presently projected will be available from sources like Canada and Mexico may well be dictated by whether gas pipeline capacity is available to transport it. If the almost unanimous comments of their elected officials are any indication, the people of the West are willing to accept whatever additional cost may be involved in order to be assured that pipeline capacity will be adequate to meet all future contingencies.

Prior to final certification of a Western Leg, there may be better information about potential supplies to determine whether the proposed "1580 Design" is over- or under-sized for the anticipated need. Before the issuance of a final certificate of public convenience and necessity, 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 pre-building to take direct deliveries for the West Coast of any short-term increases in Canadians exports from Alberta. Any deviation from the capacity of the "1580 Design" will directly reflect any material changes in gas supply or pipeline capacity projections that occur between now and the date the certificate is issued. The Secretary's determination shall be communicated to the FPC and shall be binding on it for purposes of its certification.

### CHAPTER X—RELATIONSHIP OF THE DECISION TO THE RECOMMENDATION OF THE FEDERAL POWER COMMISSION

Section 7(b) of ANGTA requires a statement of the "reasons for any revision, modification of, or substitution for the Commission (FPC) recommendation."

This *Decision* is consistent with the FPC recommendation as set forth in its letter of transmittal dated May 2, 1977:

> We recommend that an overland route through Canada be selected, if such a route is made available by the Government of Canada on acceptable terms and conditions.

The condition has been met, and an overland route is selected by this *Decision*.

Two FPC Commissioners recommended the Alcan system. The other two FPC Commissioners recommended the Arctic Gas system "conditioned upon timely affirmative decisions by the Government of Canada to make the route available," but they said that otherwise Alcan should be approved. There was a failure of that condition with respect to Arctic Gas when the Arctic Gas route was rejected by the Canadian National Energy Board. Therefore, this *Decision* is in accordance with the specific system recommendation of all FPC members who participated in the May 2, 1977, *Recommendation to the President.*[32]

The Federal Power Commission recommended the deferral for "one to two years the certification of any new facilities for the western leg. . . ." This *Decision* provides for approval of the western leg facilities subject to the same condition as other portions of the project. The Secretary of DOE is authorized to make a determination of the necessary capacity for both the western and eastern legs at the time of the issuance of the final certificate of public convenience and necessity. This approval is necessary to entitle all such facilities to the expeditious authorization pursuant to Section 9 of ANGTA.

This *Decision* differs from the *Recommendation* of the Federal Power Commission in one other material respect. The Commission suggested alternative financing plans—a private risk bearing model and a consumer risk bearing model. In conjunction with private risk bearing, the FPC suggested the use of a "formula" price mechanism whereby a city gate market value indicator (MVI) price would be established. The wellhead price would be the difference between the transportation cost and the MVI price.

This *Decision* requires a private assumption of the risk of noncompletion. However, the determination of the wellhead price should be pursuant to the pricing provisions in the pending National Energy Act. Those provisions, along with the financing proposals made herein, will ensure an equitable sharing of project

[32] The only difference between the Alcan system before the Federal Power Commission and the Alcan system herein approved is the contemplated expansion of pipeline capacity south of Whitehorse, Yukon, and a pipeline rerouting near Whitehorse to facilitate any future connection of Mackenzie Delta Reserves.

risks and constitute the best method for securing a private financing of the project.

## Chapter XI—Agreement With Canada

### ISSUES

There are certain potential risks associated with any project involving more than one country. These derive from complications which arise when a large scale construction project is subject to the jurisdiction of two federal governments, Canada and the U.S., and the interests of the two governments are not always identical. The potential risks involved were explored extensively during the FPC proceedings on Alaska gas, and further in the Senate hearings and debates prior to ratification of the Transit Pipeline Treaty with Canada. These debates served to crystallize the most important of these issues.

An example of the divergence of interests of the two countries was the re-routing of the main pipeline through Dawson which was required by the NEB's July 4th Decision. That re-routing was designed from the Canadian perspective to bring a major gas transportation system within reach of their Mackenzie Delta reserves. From the U.S. perspective, the re-routing was a costly alternative to accommodate an uncertain eventuality—construction of the Dempster Line—which might never occur.

During the course of the negotiations, a compromise was worked out on this point which effectively serves the interests of both countries. In return for routing the main line along the original Alcan route, the U.S. agreed to share the costs of extending the Dempster Highway lateral from Dawson to Whitehorse. Whitehorse will be the point at which the lateral pipeline from the Mackenzie Delta gas fields connects to the main line when and if the lateral is built.

Virtually all of the other issues which were raised in the FPC proceedings and the Senate hearings and debates were the subject of lengthy negotiations with the Canadians. The discussion which follows covers the issues of primary Canadian concern in reaching this decision, along with the resolution of those issues which has been achieved through the negotiations.

#### Taxes and impact assistance

The first risk with a trans-Canada system is unanticipated costs arising from potential Canadian taxes and impact asssitance. The FPC proceeding considered the risk of taxes imposed by the Canadian provincial governments, and it was concluded that Canadian legislation or compacts would be necessary to bind the Canadian provinces directly to the antidiscriminatory tax provisions of the Treaty.

The Canadian Government has undertaken to negotiate Federal-Provincial agreements with the three western provinces—British Columbia, Alberta and Saskatchewan—to assure their implementation of the Treaty. The Federal Government has obtained public statements from all three provinces endorsing the principles of the treaty, and those statements are annexed and made part of the Agreement. These statements and subsequent Federal—Provincial Agreements, backing up the unequivocal responsibility of the Canadian Government under the Treaty, will provide adequate assurance on this point.

The degree of practical protection afforded by the Treaty was subject to some question in the Yukon Territory, as there are currently no similar pipelines against which to measure possible discriminatory treatment. Therefore, ad valorem (property) taxation in the Yukon was negotiated as part of the Agreement on Principles. The agreed rate of property taxation is essentially comparable to that in Alaska, and will continue for 25 years or until a similar pipeline is built, at which time the Treaty protections will apply. The only contingency which would change the agreed taxation regime is if the State of Alaska changes its property tax regime.

A related issue was the $200 million socioeconomic impact payment recommended by the NEB in its July 4th decision. There are precedents in the United States for socioeconomic impact assistance. Normally, however, compensation for such impacts has been through federal government loans and subsidies. In negotiations with Canadian representatives, it was strongly urged that this payment be structured as a loan from the pipeline company to be repaid through reduction of future property-tax liability. In fact, such an arrangement has been worked out between the Canadian project sponsors and the Canadian government. As a result, cost of service to U.S. consumers will not be affected by this arrangement.

### Native claims

A source of additional concern is the settlement of Canadian native claims. Some parties have questioned whether the cost of the settlement—the cost was almost $1 billion in the case of Alaska native claims—would be imposed on consumers of Alaska gas through some type of transit fee or tax. The Canadian government has publicly stated on a number of occasions that it considers settlement of native claims as an internal Canadian matter to be resolved separately from any trans-Canada pipeline consideration. Canada has also undertaken to assure the United States that no charges against the pipeline related to the settlement of such claims will be levied.

Another concern has been that the uncertain status of a Canadian native claims settlement may affect Alcan's ability to secure financing. Lenders might be reluctant to commit funds without firm assurance on the final schedule for completion of the pipeline.

The Agreement on Principles commits both countries to a timetable which is specified in the Agreement. The Agreement also commits both countries to seek legislation as required to remove any delays or impediments to timely and efficient construction. This legislation, particularly when combined with the incentive scheme to reduce cost overruns in Canada, will provide the strongest possible assurances to lenders that both governments intend for this project to be completed as quickly, and at as low a cost, as possible.

### "Canadian Content" regulations

It has been argued that the "Canadian content" regulations, issued by the NEB to assure that Canadian firms and workers receive the maximum economic benefits from pipeline projects in Canada, could increase costs. One part of the Agreement specifically addresses this point, and commits each government to the principle that the supply of goods and services will be on generally competitive terms. Specific remedies are included in that section of the Agreement of consideration in the event that the competitive terms of supply which are sought by the Agreement are not being met.

Employment

Finally, a trans-Canada project would have fewer employment opportunities for U.S. workers than the El Paso project. It is estimated that during the construction period, El Paso would account for 324,000 man-years of employment in the United States compared to 221,000 for Alcan. In the year of greatest employment, El Paso would have a 121,000 to 84,000 man-year advantage over Alcan.

The El Paso project is also more labor intensive. Such increased employment opportunities, however, show up in a significantly increased cost of service for the El Paso system. Labor costs in Canada are lower than in the United States, and the operating costs of an all-pipeline system through Canada will be significantly lower than for the El Paso LNG system. Also, the lower cost and higher fuel efficiency of a trans-Canada pipeline make its NNEB substantially higher than that of El Paso.

The important point is that neither project will solve the unemployment problems of either country. Although the difference in man-years of employment between the two projects is large in an absolute sense, it translates into a 0.035 percent difference in the U.S. unemployment rate. This difference would be offset by the unemployment impacts on the U.S. of curtailed Canadian gas deliveries in the event that lack of access to the Mackenzie Delta reserves reduced Canada's ability to meet existing export commitments.

* * * * * * *

The Agreement on Principles provides assurances on routes, taxation levels, project delays, and other critical matters. A section-by-section analysis is provided below. This Agreement, along with the Transit Pipeline Treaty, protects the project from unfair or discriminatory charges that would otherwise threaten the savings to U.S. consumers. Canada also has an excellent record of living up to its commitments in similar joint agreements with the U.S. In fact, the kind of assurance on time, taxes, routes, tariffs and a host of other issues spelled out in the Agreement on Principles probably exceeds the level of commitment that would have been available at this time on any all-American project.

## ANALYSIS OF THE AGREEMENT WITH THE GOVERNMENT OF CANADA

Paragraph 1: Pipeline route

This paragraph defines the Pipeline which is the subject of the Agreement as that which will follow the route described in the first Annex to the Agreement, and requires that all necessary action be taken to authorize the construction and operation of the Pipeline consistent with the principles of the Agreement.

Paragraph 2: Expeditious construction; timetable

Subparagraph (a) lays out a timetable for commencement of construction and commits both Governments to take measures to complete issuance of all authorizations in time to allow initial operation of the Pipeline by January 1, 1983. The timetable calls for construction beginning in Alaska by January 1, 1980, and main line pipelaying beginning in the Yukon by January 1, 1981. Although heavy pipeline construction activity in the Yukon cannot start before early 1981, preconstruction activities, such as final routing studies and highway bridge reinforcement for heavy equipment traffic, can proceed prior to that date.

Subparargraph (b) assures that all charges for routine authorizations, such as licenses and certficates, as well as charges for right-of-way, will just be reasonable and nondiscriminatory. Subparagraph (c) commits both Governments to facilitating expeditious construction of the Pipeline consistent with the respective regulatory requirements of the two Governments, such as those in the areas of worker safety, environmental protection, and quality control.

Paragraph 3: Capacity of pipeline and availability of gas

Subparagraph (a) deals with the initial throughput capacity of the Pipeline, requiring that this capacity be sufficient to meet the contractual requirements of shippers when those requirements arise. The intention is that it would initially be sized for 2.4 billion cubic feet per day (bcfd) of gas from Alaska, with provision for up to 1.2 bcfd of gas from Canada's Mackenzie Delta at the time the Dempster Highway lateral pipeline (called "the Dempster Line") is built to connect those reserves. It is expected that this intention will be carried out by installing larger-diameter or thicker-walled pipe south of the interconnection point near Whitehorse, then adding additional compressor capacity at the time the Dempster Line is constructed. The choice between larger-diameter and thicker-walled pipe will be made at the conclusion of a testing program to assess the safety and reliability of the two alternatives. The testing program is provided for in Paragraph 10.

Subparagraph (a) also provides that authorizations will be granted, subject to regulatory requirements, for the Dempster Line and any further expansions of capacity (such as that which may subsequently be requested to transport additional Alaska gas).

Subparagraph (b) defines and limits arrangement whereby the Pipeline will provide gas service to remote communities, through or near which it passes. Prior to the time when the Dempster Line is in service, the gas provided will be Alaska gas, subject to contemporaneous replacement by equivalent volumes of Canadian gas being made available for export.

There is a limit of $5 million Canadian on capital costs to be incurred by U.S. shippers for provision of this service. Costs outside that limit will be reflected in the cost of service to the communities involved.

Paragraph 4: Financing

Subparagraph (a) states the understanding of both Governments that the project will be privately financed. It is also recognized that both Governments have to assure themselves that the project can be so financed before construction is allowed to begin.

Subparagraph (b) commits both Governments to use a variable rate of return on pipeline company equity capital as an incentive device to avoid cost overruns and to minimize costs consistent with sound pipeline management. Under this device, a higher-than-usual rate of return on pipeline company equity capital is allowed in the cost of service if the company is able to meet or better its estimates of capital costs for the project. Conversely, a lower-than-usual rate of return on equity is included in the cost of service if the project overruns its capital cost estimates. The base capital cost estimates which will be used for administering the variable rate of return device in Canada are set forth in the Agreement as Annex III.

Although the details of the variable rate of return device remain to be worked out by the Federal Power Commission and the Canadian National Energy Board, it will have the effect of insulating the consumer somewhat from the effect of cost overruns in project construction. If the amount of capital costs reflected in the cost of service is relatively low, then the return-on-equity component of that cost is allowed to be higher than usual. On the other hand, if the total capital costs are higher than estimated, the increased cost of service can be offset by reducing that portion of it which is included for return on pipeline company equity capital. The overall effect on the cost of service is to narrow somewhat the expected range by trading off return to the pipeline company against performance by the company in holding down capital costs. Additional information on the variable rate of return concept is given in the section of the *Decision* dealing with financing.

Subparagraph (c) states that neither the variable rate of return on equity nor any unusual provisions in the debt instruments concluded in financing the main line will be allowed to interfere with the financing of the Dempster Line.

Paragraph 5: Taxation and provincial undertakings

Subparagraph (a) reiterates commitments of the two Governments under the Transit Pipeline Treaty and attaches statements by the Governments of the three western provinces expressing their agreement with the principles in the Treaty. In addition to guarantees against interruptions in flow, the Treaty covers fees, duties, taxes or other monetary charges, and assures that such charges will be the same for transit pipelines as for similar pipelines located within the jurisdiction of the responsible public authorities within each country.

As there are no similar pipelines in the Yukon Territory, it was desirable to reach an understanding on the taxation regime applicable to the Pipeline in that Territory. Subparagraph (b) lays out the principles of that taxation regime, which is comparable to that in the State of Alaska. Those principles are as follows:

1. The Yukon Property Tax is defined as property taxes and all other direct taxes[33] which are levied exclusively or virtually exclusively on the Pipeline. (Clause i)

2. Prior to authorization of initial operation of the Pipeline, the Yukon Property Tax will not exceed the following:

1980—$5 million Canadian;
1981—$10 million Canadian;
1982—$20 million Canadian; and
Any year after 1982 during which operation of the Pipeline is not yet authorized—$25 million Canadian. (Clause ii)

3. From the first full year that the Pipeline is authorized to open operation through 2008 (or until the Dempster Line is authorized to open, if that occurs earlier), the Yukon Property Tax will not exceed $30 million Canadian, adjusted for inflation after 1983 using the Canadian Gross National Product price deflator (the GNP deflator). (Clause i)

4. The $30 million maximum level of taxation applies to the Pipeline at a throughput of 2.4 bcfd of U.S. gas and 1.2 bcfd of Canadian gas. If the capacity of the Pipeline is increased for U.S. gas prior to the connection of the Dempster Line, the $30 million base figure could be increased by the same proportion as the increase in gross asset values of the Pipeline facilities. (Clause vi)

5. If at the end of 1987 it is found that the per capita revenues received from property taxes, other than the Pipeline, plus grants to local governmental units, have increased during the period 1983 through 1987 at a faster rate than the GNP deflator, the Yukon Property Tax may undergo a one-time adjustment for the year 1987 to raise the permitted maximum to the level it would have been, had it been increasing at the rate of increase of other YTG per capita revenue. (Clause iv)

6. After January 1, 1988, the Yukon Property Tax is permitted to rise either with the GNP deflator or with the rate of increase in YTG per capita revenue (excluding tax on the Pipeline), whichever is greater. (Clause v)

7. If the Alaska property tax rate on pipelines increases between now and 1983 at a rate faster than the Canadian GNP deflator, an adjustment in the permitted $30 million maximum is allowed; and after leave to open the Pipeline in the Yukon is granted, the permissible Yukon property tax may be adjusted to reflect increases of Alaska property tax on the Pipeline greater than increases otherwise permitted in the Yukon Property Tax. (Clauses vii and viii)

8. Clause ix provides that the Yukon socioeconomic fund costs will not be reflected in cost of service to U.S. shippers. No other special fund having an effect on cost of service will be permitted in the Yukon unless such a fund is required by the State of Alaska.

9. If the Dempster Line is connected, the Yukon Property Tax will be governed by the tax treatment applied to the Dempster Line, under the terms of the Transit Pipeline Treaty (clause iii). In Subparagraph (c) the Canadian Government will endeavor to ensure that tax treatment of the Dempster Line in the Northwest

[33] Under Canadian law, the Yukon Territorial Government can impose only direct taxes. Indirect taxes can only be levied by the Canadian Federal Government, and are, therefore, governed adequately by the Transit Pipeline Treaty.

Territory is reasonably comparable to that in the Yukon Territory. (Clause iii and Subparagraph (c))

10. If the Dempster Line is not connected, the permissible limit of the Yukon Property Tax will expire on December 31, 2008 (25 years after the date when the Alaska gas is expected to begin flowing), at which time it will be renegotiated. (Clause iii)

Paragraph 6: Tariffs and cost allocation

Subparagraph (a) outlines the general methods of cost allocation for the portions of the Pipeline in Canada. The Pipeline will be divided into zones (Annex II contains the description of the zones) corresponding to segments of the system delineated by any of the following boundaries:

Gas input and takeout points.

Changes in Pipeline ownership.[34]

Cost of service to each shipper in each zone will be determined by allocating the total costs of constructing and operating the Pipeline in that zone among the shippers transporting gas through it in proportion to the volumes of gas[35] transported for each shipper.

Subparagraph (b) describes the cost allocation method for Zone 11 (the extension of the Dempster Line from Dawson to Whitehorse known as the "Dawson Spur") if and when the Dempster Line is constructed. In general, the cost of service for the Dawson Spur is to be shared by Canadian and U.S. shippers. The proportionate sharing is to be linked to the degree of cost overruns sustained in constructing the Canadian segments of the Pipeline. In no event is the share to be paid by U.S. shippers less than the fraction of the U.S. gas transported by the system after Canadian gas has been connected to the system. The cost service to U.S. shippers will be affected more by reduced cost overruns than by the U.S. share of the cost of service for the Dawson Spur.

For a case with system transportation of 2.4 bcfd of U.S. gas and 1.2 bcfd of Canadian gas, the U.S. shippers' share of the Dawson Spur cost of service would be two-thirds if cost overruns were 45 percent. If cost overruns are reduced from 45 percent, the U.S. shippers' share of the cost of service increases on a straight-line basis, until at an overrun level of 35 percent, the U.S. shippers' share is 100 percent.

If U.S. gas is a larger proportion than two-thirds of the total gas carried in the Pipeline, the minimum proportion of the cost of service on the Dawson Spur to be paid by U.S. shippers is correspondingly higher. If the system is carrying three-quarters U.S. gas, for example, then the minimum proportion of the cost of service on the Dawson Spur which will be paid by U.S. shippers is 75 percent. From that minimum, the U.S. shippers' share of the cost of service increases with reduced cost overruns until their share reaches 100 percent at the 35 percent cost overrun level. The de-

[34] In order to assure full Federal Government jurisdiction over the Pipeline, the Canadian National Energy Board required the sponsoring companies to restructure their corporate form. The pipeline company sponsors are to form a Federally-chartered umbrella company, Foothills Pipe Lines, Ltd., which will own 51 percent of subsidiaries which will construct and operate segments of the Pipeline within the different provinces. The other 49 percent of each subsidiary will be owned by the respective parent companies of Foothills in their traditional business areas.

[35] Volumes of commingled gas streams will be adjusted to reflect the original Btu content of the source gas and such volumes will be used for allocating costs.

gree of cost overrun between 35 and 45 percent always corresponds to the same U.S. shippers' share of the cost of service on the Dawson Spur; only the minimum U.S. shippers' share varies with the proportion of total gas transported which is U.S. gas.

This cost-sharing arrangement is intended to provide benefits to transportation of Canadian gas which would have been provided by diverting the Pipeline north through Dawson City and along the Klondike Highway as required by the National Energy Board. Had the diversion been implemented, U.S. shippers would have been paying a volumetric proportion of the cost of service of the main line between Dawson and Whitehorse after the Dempster Line was connected, and all of the cost of service for that segment if the Dempster Line was never connected. Under the agreed arrangement, U.S. shippers will pay a volumetric proportion of the cost of service on a smaller, less expensive pipeline from Dawson to Whitehorse only after the Canadian gas is connected, and will pay nothing for that segment if the Dempster Line is never built. The agreed arrangement provides the same transportation benefits to Canadian gas at lower cost to both Canadian and U.S. shippers.

The agreed arrangement also imposes a ceiling on U.S. liability for the Dawson Spur at 35 percent above filed costs. The Canadians, in turn, can credit savings achieved on the main line system against cost overruns on the Dawson Spur prior to applying the ceiling. The savings that can be credited against the cost overruns on the Dawson Spur may be either of the following:

A volumetric proportion of savings achieved in segments through which joint volumes will be transported; and

100 percent of savings achieved in segments which will carry only U.S. gas.

However, at a minimum, the U.S. shippers' share of the cost of service on the Dawson Spur will be the fraction of the total gas carried in the Pipeline which is U.S. gas. More detail on the specifics of cost allocation for the Dawson Spur is given in Annex III to the Agreement.

Subparagraph (c) of this Paragraph in general provides for review and subsequent agreement by both Governments on cost allocation methods in the event that volumes of gas to be shipped exceed the efficient transmission capacity of the Pipeline. Subparagraph (d) limits costs for the Dawson Spur allocated to U.S. shippers to those that would be incurred for installation of a 42-inch system, plus those installed within 3 years of the date when the system commences operation. Subparagraph (d) also requires the system installed for the Dawson Spur to be the same as that for the Dempster Line, in order to prevent loading of costs onto the Dawson Spur.

Paragraph 7: Supply of goods and services

Subparagraph (a) ensures that contracting for supply of goods and services to the Pipeline will be on generally competitive terms. This provision is intended to prevent cost overruns and time delays due to Canadian source restrictions on procurement for pipeline projects constructed within Canada.

Subparagraph (b) provides a mechanism for presenting grievances when the objectives with regard to competitive terms in Subparagraph (a) are not being met. Subparagraph (b) also specifies possible actions to be taken in the event of a favorable determination on a plaintiff's grievance including:

Renegotiation of contracts, or
Reopening of competitive bidding.

Paragraph 8: Coordination and consultation

This paragraph provides for appointment by both Governments of a senior official to represent that Government in periodic consultations on progress in implementing this Agreement. The respective senior officials may, in turn, designate additional representatives to work out any particular problems which may arise in the course of constructing and operating the Pipeline.

Paragraph 9: Regulatory authorities—consultation

This paragraph provides for consultation between the respective regulatory authorities in the U.S. and Canada, primarily the U.S. Federal Power Commission and the Canadian National Energy Board. In particular, the two authorities will need to work out matters relating to financing, tariffs, taxation and cost allocation as they relate to determination of the cost of service for the Pipeline.

Paragraph 10: Technical study group on pipe

The two Governments are agreed that a higher-capacity pipeline system than was proposed by the sponsoring companies is to be installed south of the interconnection point for the Dempster Line at Whitehorse, in order to carry joint gas volumes more efficiently. However, there is some reservation, particularly on the part of the Canadian Government and the Canadian pipeline company sponsors, about the technical feasibility of a higher-pressure system, such as had been proposed by the Arctic Gas consortium. Although Canadian Government representatives are agreed on the need for a higher-capacity system, their preference on the grounds of expected safety and reliability is for larger-diameter pipe, which has many of the same advantages in increased efficiency as the higher-pressure system.

Subparagraph (a) establishes a joint technical study group for the purpose of evaluating the relative merits of the larger-diameter and higher-pressure systems which have been suggested, as well as any other combinations of pressure and pipe size which might achieve objectives of increased efficiency. The 48-inch, 1,260 pounds per square inch (psi) design which was proposed by the applicant and will likely be installed from Whitehorse north to the Prudhoe Bay field will also be evaluated by the group. Final decisions based on the results of the testing program will remain the responsibility of the respective regulatory authorities in the two countries.

Subparagraph (b) states that whatever higher-capacity system is chosen will be installed from the interconnection point near Whitehorse to the point near Caroline, Alberta, where the Pipeline bifurcates into a western and an eastern leg.

Paragraph 11: Direct charges by public authorities

Subparagraph (a) provides that either Government can request consultations in the event that any public authority seeks to impose a direct charge on the Pipeline which might be considered properly the responsibility of the sponsoring company, rather than an item which should be included in the cost of service.

Subparagraph (b) identifies generally the types of direct charges by public authorities which will be permitted to be included in the cost of service. Such charges will include only:

Those considered by the appropriate regulatory authority to be just and reasonable on the basis of accepted regualtory practice, and

Those normally imposed on natural gas pipelines in Canada.

A list of examples of direct charges is attached to the Agreement as Annex IV and includes:

Extraordinary highway maintenance due to heavy vehicle traffic,

Airfield and airstrip repairs,

Drainage maintenance, and

Erosion control, etc.

Direct charges will be subject to the tests in the appropriate legislation prior to inclusion in the cost of service.

Paragraph 12: Other costs

This Paragraph provides that no charges will be considered for inclusion in the cost of service other than those:

Imposed by a public authority under the terms of the Agreement or the Transit Pipeline Treaty,

Normally paid by natural gas pipelines in Canada under accepted regulatory practice, or

Caused by Acts of God or other unforeseen circumstances.

Paragraph 13: Compliance with terms and conditions

This Paragraph provides that each Government will implement the principles directly applicable to construction, operation and expansion of the Pipeline through imposition of terms and conditions on the authorizations it issues. In the event that a Pipeline owner does not fulfill one or more of the terms and conditions, the Government will not be held responsible for that nonfulfillment, but will take appropriate action to cause the owners to remedy or intergrate the adverse consequences of that nonfulfillment.

Paragraph 14: Legislation

This Paragraph commits both Governments to seek expeditiously all legislative authorities which might be required to implement the Agreement and to facilitate timely and efficient construction of the Pipeline. This provision specifically refers to legislation to remove delays to construction of the Pipeline.

Paragraph 15: Entry into force

This paragraph provides that the Agreement will become effective upon signature, and will continue in effect for 35 years and thereafter until terminated on 12 month's notice by either Government. The provisions of the Agreement which required legislative action will become effective when the required legislative action has been completed.

At the end of the agreement there are several Annexes which append specific information or explain a particular feature of the Agreement in more detail.

Annex I: Description of the route

(Self-explanatory).

Annex II: Zones for the pipeline in Canada

This Annex specifically identifies the zones for cost allocation under the method described in Paragraph 6. It gives the boundaries of the zones.

Annex III: Cost allocation in Zone 11

This Annex describes the cost allocation agreement for the Dawson Spur, which was outlined in Paragraph 6, in more detail. In particular, the computation of the ceiling on U.S. shippers' liability for the cost of service on the Dawson Spur is set forth in some detail.

The Annex also contains detailed specification of the filed capital costs for Canadian portions of the system which will be used to determine cost overruns for the purposes of cost allocation for the Dawson Spur. Possible adjustments of those costs in limited circumstances are also covered.

Annex IV: Direct charges by public authorities

This Annex is a list of typical direct cost items for use with the limitation on direct charges by public authorities in Canada; the limitation is in Paragraph 11 of the Agreement.

Annex V: Statements by the provincial governments

Public statements by the Governments of the three western provinces are attached in which they agree to the principles of the Transit Pipeline Treaty. Each also undertakes to work out with the Canadian Government a Federal-Provincial Agreement.

## CHAPTER XII—SUMMARY OF COMMENTS RECEIVED

Throughout the period during which an Alaska natural gas transportation system has been under consideration, many comments concerning the decision have been sent to the various Federal agencies involved in the decision process. Comments have come from all parts of the American public, including private citizens, businesses, labor unions, municipalities, legislators and Governors. They ranged from expressions of support for a specific proposal to suggestions of alternative and often innovative methods of building a gas delivery system.

By far, the majority of comments were received within the past few months in response to a *Federal Register* notice on June 14, 1977, advising the public of Section 6(b) of the Alaska Natural Gas Transportation Act of 1976 which invites comments from Governors, municipalities, and other interested parties. Letters soliciting comments were written to the Governors of all the States, and meetings were held on several occasions with a committee of State Public Utility Commissioners.

The comments received in the period since the FPC's *Recommendation to the President* have been of two basic types—those supporting a specific proposal, and those commenting on certain aspects of the FPC recommendations. Almost all the letters received favored the delivery of the North Slope gas to the lower-48 states. Very few suggested that construction of a delivery system be significantly delayed or that no system be built.

### COMMENTS ON SPECIFIC PROJECTS

#### Arctic gas

The supporters of Arctic Gas most often cited Arctic's claims of lower cost of service and fuel use; ability to connect Prudhoe Bay and Mackenzie Delta reserves with one pipeline; and the opportunity to maintain Canadian gas exports once the Mackenzie Delta reserves were connected.

The unfavorable comments generally concerned the environmental impacts of crossing the Arctic National Wildlife Range (ANWR); higher potential for delay and cost overrun due to winter construction, use of snowroads, and regulation by two countries. The unsettled status of the Canadian native land claims was stressed as a factor which would cause delays or preclude construction.

Before the July 4th Canadian NEB decision, the Arctic Gas proposal received support from municipalities and businesses in the Midwest and California; the Governors of Arkansas, Kansas, Wisconsin, Minnesota, Massachusetts, Ohio, Maryland, Illinois; and many private citizens from all parts of the country. The Governors of California and Montana also supported an overland route.

#### El Paso

Support for the El Paso proposal was primarily based on the fact that El Paso would lie entirely within the United States. According to its supporters, this fact would result in greater domestic employment, higher tax payments, better security of supply, and regulatory control by one country. Another favorable point for El Paso cited was that it used the existing Alyeska transportation corridor and facilities.

The principal negative comments concerned El Paso's higher cost of service; the location of its LNG plant in active seismic zones; difficulty of siting the regasification plant in Southern California; and the possibility that it would foreclose delivery of additional Canadian gas supplies.

Support for the El Paso proposal came from various state AFL–CIO offices, maritime labor unions, some private citizens, and the Governors of Alaska, New Mexico, Arizona, Texas, Alabama, New York and Washington.

#### Alcan

Alcan's supporters often cited this proposal as an example of the success of the National Environmental Policy Act (NEPA) because the proposal developed as an alternative which achieved the economies of scale of a pipeline while avoiding the environmentally sensitive ANWR and Arctic regions. Alcan also received support because it generally follows existing transportation corridors. It seemed even greater after the NEB selected the Alcan proposal and stated that construction of a Trans-Canadian pipeline would facilitate maintenance of Canadian gas exports.

The negative comments on Alcan were that it had a less developed hearing record; would incur more delays by being subject to regulation by two countries; would lack adequate pre-construction planning, would require settlement of Canadian Native claims in southern Yukon; and would need additional environmental studies. Concerns were raised about the conditions imposed by the NEB, such as the socioeconomic impact fund and the requirement to increase capacity to carry Canadian gas in the system.

Support for the Alcan proposal has come from the major environmental organizations and the Governors of Wyoming, Nevada, Oregon, Colorado, and Utah.

## COMMENTS ON SPECIFIC FPC RECOMMENDATIONS

### Formula wellhead pricing

The producers and the State of Alaska strongly opposed the FPC recommendation for "formula pricing" of the wellhead price. They contended that this approach forced the producers to share the risk of the project—even if they were not investors. This would serve to inhibit further exploration for gas in northern Alaska. They also argued this proposal would reduce the sponsor's incentive to manage the project properly.

### Minimum throughput requirements

The producers also opposed this recommendation because contending that throughput should be established by the behavioral characteristics of the reservoir and by the State of Alaska.

### Widespread distribution of gas

The members of the Artic Gas Consortium strongly opposed this recommendation. They argued that this requirement would be a disincentive for prospective members to join the consortium; would be unfair and discriminatory to companies who could purchase more than the maximum; and would result in discriminatory treatment of Alaskan gas compared with other fuel sources. Alcan, however, supported the widespread distribution requirement.

### Western Leg

The FPC recommendation to delay the decision on the Western Leg was opposed by Arctic, Alcan and the State of California. It was argued that this recommendation is inconsistent with the requirements of Alaska Natural Gas Transportation Act. They also felt that new facilities will be required to deliver Alaska gas to the West.

## ALASKA NATURAL GAS TRANSPORTATION SYSTEM: WAIVERS OF LAW

**Waivers of Law.**—The President submitted to the Congress findings and proposed waivers of law on October 15, 1981. The President's proposed waiver was approved by Public Law 97–93 (Dec. 15, 1981; 95 Stat. 1204) pursuant to the procedures of section 8 of the Alaska Natural Gas Transportation Act of 1976.

## MESSAGE TO THE CONGRESS SUBMITTING A PROPOSED WAIVER OF LAW. OCTOBER 15, 1981

*To the Congress of the United States:*

The Alaska Highway Pipeline route for the Alaska Natural Gas Transportation System was chosen by President Carter and approved by Congress in 1977. There was a strong Congressional endorsement that the pipeline should be built if it could be privately financed. That has been my consistent position since becoming President, as communicated on numerous occasions to our good neighbors in Canada and I am now submitting my formal findings and proposed waiver of law.

As I stated in my message to Prime Minister Trudeau informing him of my decision to submit this waiver:

> My Administration supports the completion of this project through private financing, and it is our hope that this action will clear the way to moving ahead with it. I believe that this project is important not only in terms of its contribution to the energy security of North America. It is also a symbol of U.S.-Canadian ability to work together cooperatively in the energy area for the benefit of both countries and peoples. This same spirit can be very important in resolving the other problems we face in the energy area.

This waiver of law, submitted to the Congress under Section 8(g) of the Alaska Natural Gas Transportation Act, is designed to clear away governmental obstacles to proceeding with private financing of this important project. It is critical to the energy security of this country that the Federal Government not obstruct development of energy resources on the North Slope of Alaska. For this reason, it is important that the Congress begin expeditiously to consider and adopt a waiver of those laws that impede private financing of the project.

RONALD REAGAN.

THE WHITE HOUSE, *October 15, 1981.*

### FINDINGS AND PROPOSED WAIVER OF LAW

Pursuant to the provisions of the Alaska Natural Gas Transportation Act of 1976 (ANGTA) 15 U.S.C. §719, *et seq.*, a transportation system to transport Alaska natural gas to consumers in the continental United States was selected and approved by Congress in 1977.

I find that certain provisions of law applicable to the Federal actions to be taken under Subsections (a) and (c) of Section 9 of ANGTA require waiver in order to permit expeditious construction and initial operation of the approved transportation system. Accordingly, under the provisions of Section 8(g)(1) of ANGTA, I hereby propose to both Houses of Congress a waiver of the following provisions of law, such waiver to become effective upon approval of a joint resolution under the procedures set forth in Sections 8(g)(2), 8(g)(3), and 8(g)(4) of ANGTA.

Waive P.L. 95–158† [Joint Resolution of approval,* pursuant to Section 8(a) of ANGTA, incorporating the President's *Decision*] in the following particulars:

Section 1, Paragraph 3, and Section 5, Conditions IV–4 and V–1, of the President's *Decision,* in order to permit producers of Alaska natural gas to participate in the ownership of the Alaska pipeline segment and the gas conditioning plant segment of the approved transportation system; *Provided,* however, that any agreement on producer participation may be approved by the Federal Energy Regulatory Commission only after consideration of advice from the Attorney General and upon a finding by the Federal Energy Regulatory Commission that the agreement will not (a) create or maintain a situation inconsistent with the antitrust laws, or (b) in and of itself create restrictions on access to the Alaska segment of the approved transportation system for nonowner shippers or restrictions on capacity expansion; and

Section 2, Paragraph 3, First Sentence, of the President's *Decision,* to include the gas conditioning plant in the approved transportation system and in the final certificate to be issued for the system; and the application of Section 5, Condition IV–2 of the President's *Decision* to the gas conditioning plant; and

Section 5, Condition IV–3, of the President's *Decision; Provided,* however, that such waiver shall not authorize the Federal Energy Regulatory Commission to approve tariffs except as provided herein. The Federal Energy Regulatory Commission may approve a tariff that will permit billing to commence and collection of rates and charges to begin and that will authorize recovery of all costs paid by purchasers of Alaska natural gas for transportation through the system pursuant to such tariffs prior to the flow of Alaska natural gas through the approved transportation system—

(a) to permit recovery of the full cost of service for the pipeline in Canada to commence—

(1) upon completion and testing, so that it is proved capable of operation; and

(2) not before a date certain, as determined (in consultation with the Federal Inspector) by the Federal Energy Regulatory Commission in issuing a final certificate for the approved transportation system, to be the most likely date for the approved transportation system to begin operation; and

(b) to permit recovery of the actual operation and maintenance expenses, actual current taxes and amounts necessary to

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† See: Executive Office of the President, Energy Policy and Planning, *Decision and Report to Congress on the Alaska Natural Gas Transportation System* (September 1977) (hereinafter referred to as President's *Decision*); and see H.J. Res. 621, Pub. L. No. 95–158 (1977), wherein the President's *Decision* was incorporated and ratified by Congress pursuant to Section 8(a) of ANGTA.

* 15 U.S.C. §719f nt.

service debt, including interest and scheduled retirement of debt, to commence—

(1) for the Alaska pipeline segment—

(A) upon completion and testing of the Alaska pipeline segment so that it is proved capable of operation; and

(B) not before a date certain, as determined (in consultation with the Federal Inspector) by the Federal Energy Regulatory Commission in issuing a final certificate for the approved transportation system, to be the most likely date for the approved transportation system to begin operations; and

(2) for the gas conditioning plant segment—

(A) upon completion and testing of the gas conditioning plant segment so that it is proved capable of operation; and

(B) not before a date certain, as determined (in consultation with the Federal Inspector) by the Federal Energy Regulatory Commission in issuing a final certificate for the approved transportation system, to be the most likely date for the approved transportation system to begin operation.

Waive Pub. L. No. 688,* 75th Cong., 2d Sess. [Natural Gas Act] in the following particulars:

Section 7(c)(1)(B) of the Natural Gas Act to the extent that section can be construed to require the use of formal evidentiary hearings in proceedings related to applications for certificates of public convenience and necessity authorizing the construction or operation of any segment of the approved transportation system; *Provided*, however, that such waiver shall not preclude the use of formal evidentiary hearing(s) whenever the Federal Energy Regulatory Commission determines, in its discretion, that such a hearing is necessary; and

Sections 4, 5, 7, and 16 of the Natural Gas Act to the extent that such sections would allow the Federal Energy Regulatory Commission to change the provisions of any final rule or order approving (a) any tariff in any manner that would impair the recovery of the actual operation and maintenance expenses, actual current taxes, and amounts necessary to service debt, including interest and scheduled retirement of debt, for the approved transportation system; or (b) the recovery by purchasers of Alaska natural gas of all costs related to transportation of such gas pursuant to an approved tariff; and

Sections 1(b) and 2(6) of the Natural Gas Act to the extent necessary to permit the Alaskan Northwest Natural Gas Transportation Company or its successor and any shipper of Alaska natural gas through the Alaska pipline segment of the approved transportation system to be deemed to be a "natural gas company" within the meaning of the Act at such time as it accepts a final certificate of public convenience and necessity authorizing it to construct or operate the Alaska pipeline segment and the gas conditioning plant segment of the approved transportation system or to ship or sell

*15 U.S.C. §717.

gas that is to be transported through the approved transportation system; and

Section 3 of the Natural Gas Act as it would apply to Alaska natural gas transported through the Alaska pipeline segment of the approved transportation system to the extent that any authorization would otherwise be required for—

(1) the exportation of Alaska natural gas to Canada (to the extent that such natural gas is replaced by Canada downstream from the export); and

(2) the importation of natural gas from Canada (to the extent that such natural gas replaced Alaska natural gas exported to Canada); and

(3) the exportation from Alaska into Canada and the importation from Canada into the lower 48 states of the United States of Alaska natural gas.

Waive P.L. 94–163* [Energy Policy and Conservation Act] in the following particulars:

Section 103 as it would apply to Alaska natural gas transported through the Alaska pipeline segment of the approved transportation system to the extent that any authorization would otherwise be required for—

(1) the exportation of Alaska natural gas to Canada (to the extent that such natural gas is replaced by Canada downstream from the export); and

(2) the importation of natural gas from Canada (to the extent that such natural gas replaced Alaska natural gas exported to Canada); and

(3) the exportation from Alaska into Canada and the importation from Canada into the lower 48 States of the United States of Alaska natural gas.

*42 U.S.C. §6201, *et seq.*

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# *COAL-BASED GENERATION STAKEHOLDERS*

February 5, 2001

The Honorable Frank Murkowski
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

The Honorable Jeff Bingaman
United States Senate
Washington, DC 20510

Dear Chairman Murkowski and Senator Bingaman:

We are writing to express our strong support for passage of S. 60, the "National Electricity and Environmental Technology (NEET) Act" as part of comprehensive energy legislation to be considered by the 107th Congress. A copy of the NEET bill is attached.

The Coal-Based Generation Stakeholders Group is a diverse group of investor-owned utilities, rural electric cooperatives, public power entities, coal producers, and railroads. The group believes that the option to generate electricity from coal – which remains America's most abundant energy resource – should be preserved and enhanced in order to (1) sustain our strong economy; (2) ensure the generation of affordable and reliable electricity; (3) maintain a diverse fuel supply; (4) continue to reduce emissions; and (5) provide secure jobs for American workers.

Overall emissions from U.S. coal-fired generating plants have fallen by more than 20 percent over the last 30 years, at the same time that electricity produced from coal has tripled. To continue this dramatic environmental improvement and to preserve the option for new coal-based generating plants, the development and commercialization of even more efficient and lower emitting clean coal technologies must be encouraged.

The purpose of the NEET Act is to establish a comprehensive coal-based technology program to reduce emissions by improving efficiency in existing coal-based generating plants, and to stimulate the deployment of advanced technologies to further reduce emissions and improve efficiency in new generating facilities.

The measure would accomplish this goal by enhancing funding for coal-based research and development, providing a measure of burden-sharing to improve the operational and environmental performance of existing coal-based generating facilities, and adopting financial incentives and risk sharing arrangements for a limited number of advanced clean coal technology demonstration projects.

We look forward to working closely with you on the NEET legislation and the other vital components of a comprehensive national energy strategy.

Sincerely,

Stephen Addington, President, AEI Resources
Don Blankenship, President and COO, A.T. Massey Coal Company
Travis Bowden, President and CEO, Gulf Power Company
Wayne Brunetti, President and CEO, Xcel Energy
Peter Burg, Chairman and CEO, FirstEnergy Corporation
James Crawford, Chairman and CEO, James River Coal Company
Richard K. Davidson, Chairman and CEO, Union Pacific
E. Linn Draper, Chairman, President and CEO, American Electric Power
Anthony Earley, Chairman and CEO, DTE Energy Company
Irl Engelhardt, Chairman and CEO, Peabody Group
Glenn English, CEO, National Rural Electric Cooperative Association
Dwight H. Evans, President and CEO, Mississippi Power Company
Thomas Farrell II, CEO, Dominion Energy
Jack Gerard, President and CEO, National Mining Association
Gary Goldberg, President and CEO, Kennecott Energy
David Goode, Chairman, President and CEO, Norfolk Southern
Thomas Grennan, Executive Vice President, Western Resources
Roger Hale, Chairman and CEO, LG&E Energy Corporation
Edward Hamberger, President and CEO, Association of American Railroads
Elmer Harris, President and CEO, Alabama Power Company
J. Brett Harvey, President and CEO, CONSOL Energy
Michael Haverty, President and CEO, Kansas City Southern
William Hecht, Chairman, President and CEO, PPL Corporation
G. Edison Holland, Jr. President and CEO, Savannah Electric Power Company
James Jura, General Manager, Associated Electric Cooperative
Thomas Kuhn, President, Edison Electric Institute
Steven Leer, President and CEO, Arch Coal
Bill McCormick, Chairman and CEO, CMS Energy Corporation
Charles McCrary, President, Southern Company Generation
Stephen Miller, President, Center for Energy and Economic Development
Charles Mueller, Chairman, President and CEO, Ameren Corporation
Robert Murray, President and CEO, Ohio Valley Coal Company
Alan Noia, Chairman, President, and CEO, Allegheny Energy
Erle Nye, Chairman and CEO, TXU Corporation
Paul Oakley, Executive Director, Coalition for Affordable and Reliable Energy
Roy Palk, President and CEO, East Kentucky Power Cooperative
James Pignatelli, Chairman, President and CEO, UniSource Energy Corporation
Gary Rainwater, President and CEO, AmerenCIPS
David Ratcliffe, President and CEO, Georgia Power Company
Alan Richardson, Executive Director, American Public Power Association
Rob Ritchie, President and CEO, Canadian Pacific Railway
James Roberts, President and CEO, RAG American Coal Holding

James Rogers, Chairman, President and CEO, Cinergy
Matthew Rose, President and CEO, Burlington Northern Santa Fe
Edwin Russell, Chairman, President and CEO, ALLETE
Richard Silverman, General Manager, Salt River Project
Peter Skrgic, President, Allegheny Energy Supply
John Snow, Chairman and CEO, CSX Corporation
Wesley Taylor, President, Generation Business Unit, TXU Corporation
Paul Tellier, President and CEO, Canadian National

# diversity

key to affordable and reliable

# electricity

# Enact a National Energy Program Based on Fuel Diversity.

Maintaining a diversity of supply options is key to affordable and reliable electricity. Policymakers and regulators should work together to reconcile conflicting energy, environmental, or other public policy goals. They should promote initiatives that capitalize on all of our nation's abundant natural resources. They should address challenges that limit the development and viability of fuel sources. Finally, they should implement a national energy program that:

- Maximizes the diversity of fuels and technology options available for the generation of electricity.
- Examines a comprehensive approach to the implementation of environmental regulations in order to reduce compliance costs and regulatory uncertainty.
- Promotes the development of technologies to improve energy efficiency, to enhance energy conservation, and to increase the environmental performance of fuels in the generation mix.
- Places an emphasis on market-based approaches (e.g., trading programs or results-based approaches), rather than on specific technology or prevention processes, to achieve important environmental or other societal goals.
- Removes barriers to siting electric generating stations, transmission lines, and gas pipelines.
- Revamps the process for licensing and relicensing hydropower facilities.
- Focuses the nation's tax policy on bringing new and advanced energy technologies, including electricity generation technologies, to the marketplace.
- Establishes clearly defined decision making processes that will ensure the timely resolution of conflicting policies among various government agencies.

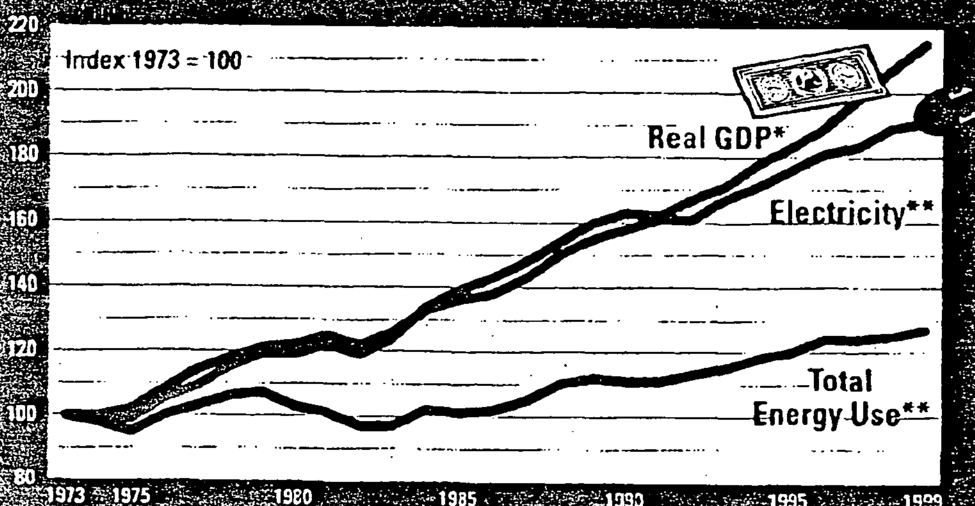
Now more than ever, a sound energy policy that promotes stability, affordability, and reliability of electricity requires a diversity of fuels and technology options and the adoption of policies that better achieve low-cost electricity supplies, attainment of environmental goals, and economic prosperity.

## Electricity powers the world.

It is the cleanest, most flexible, most controllable, and most adaptable form of energy. Electricity operates homes, offices, and industries; provides communications, entertainment, and medical services; powers computers, technology, and the Internet; and runs various forms of transportation. Electricity enhances the quality of life for its users, and contributes to the progress and success of our nation.

## Our nation's economic prosperity is closely linked to electricity growth.

Since the end of World War II, growth in electricity use has coincided with growth in the gross domestic product (GDP)—our nation's gauge of economic health. Today, the U.S. economy relies more than ever on reliable, affordable supplies of electricity, as evidenced by the ongoing growth of the digital revolution. Electricity intensity[1] in our economy shows a close relationship between electricity and the general level of economic activity. Since 1960, the intensity of electricity use in the economy, measured by electricity consumption per dollar of real GDP, has increased by more than 25 percent. In comparison, the overall intensity of energy use has decreased by more than 40 percent over the same time period.




*Source: U.S. Dept. of Commerce, Bureau of Economic Analysis **Source: Energy Information Administration

According to the Energy Information Administration (EIA), electricity demand is growing strongly. The agency projects that electricity demand will grow by 1.8 percent per year through 2020. To meet these projected increases in demand and to offset the retirements of existing power plants, the EIA forecasts that 1,310 new power plants, with a total of 393,000 megawatts of capacity, will be needed by 2020.[2] To provide some perspective, one megawatt is enough electricity to provide power to 800 homes during non-peak demand times.

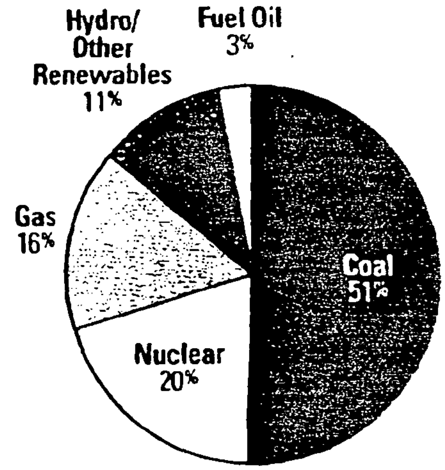
[1] Electricity intensity is a term used by analysts to relate electricity use to the gross domestic product.

[2] U.S. Department of Energy, Energy Information Administration, "Annual Energy Outlook 2001 With Projections to 2020," DOE/EIA-0383 (2001), December 2000.

## Electric companies use a diverse mix of fuels to generate electricity.

America's electricity prices are substantially lower than most of our international competitors, giving our businesses and industries a significant competitive advantage in international markets. The U.S. has enjoyed low electricity prices, in part, because we rely on a variety of fuels to generate electricity. The resulting competition among these fuels keeps prices in check.

The combination of fuel sources used is referred to as the generation mix. Today, more than half of the nation's electricity supply is generated from coal. Nuclear energy produces nearly twenty percent of the supply, while natural gas provides sixteen percent. Hydropower and, to a lesser extent, other renewable resources—such as biomass, geothermal, solar, and wind—provide nearly eleven percent of the supply. Fuel oil provides nearly three percent of the generation mix.




**Current Generation Mix**

(Numbers exceed 100% due to rounding.)
Source: Form EIA-759 and Form EIA-860B

Electric companies consider numerous factors in determining their generation mix. These include the costs to construct a power plant that will utilize a particular fuel, and the degree of risks and uncertainties associated with the use of that fuel. In addition, the price, the availability, and the reliability of different fuel supplies are important factors taken into consideration.

A diverse generation mix helps to protect companies and consumers from contingencies such as fuel unavailability, price fluctuations, and changes in regulatory practices. It also helps ensure stability and reliability in electricity supply. Finally, our reliance upon abundant, North American sources of energy to generate electricity strengthens national security.

## The fuels used to generate electricity...

Certain fuels in the electricity generation mix are better suited than others for particular applications. Typically, companies use coal-based, hydropower, nuclear, and, to a lesser extent, natural gas plants to meet "base load" electricity demand because these plants are more cost-effective and most efficient when run at full output on a continuous basis. On the other hand, pumped storage hydropower, natural gas, and oil-based units may be stopped and started quickly, making them ideal fuel sources during peak periods—the hours of the day when demand hits its highest levels.

No individual fuel is capable of providing the energy required to meet all of our nation's electricity demands. Rather, a variety of fuels—as well as increasingly more cost-effective and efficient ways to use, and conserve, energy—are needed. Indeed, different regions of our country rely upon different generation mixes, depending upon the availability and costs of fuels within those regions. For example, hydropower use is prevalent in the Pacific Northwest, natural gas in the Southwest, and coal in the Midwest. By maintaining these fuel options, consumers are provided with affordable and reliable supplies of electricity.

Here's a look at the fuels in our current generation mix:

- **Coal** is an abundant domestic resource. Recoverable U.S. coal resources total more than 296 billion tons – enough to last over 300 years at current levels of use. Coal is among the cheapest energy options available. Widespread availability and reliable transportation systems make the use of coal common in many areas throughout the U.S.

- **Nuclear energy** uses a secure fuel source (enriched uranium). In the U.S., 31 states have operating nuclear reactors. Nuclear energy offers important environmental benefits, allowing utilities to produce electricity with little or no air emissions, including carbon dioxide ($CO_2$). Use of nuclear energy is especially dominant in the northeastern portion of the U.S.

- **Natural gas** has become the primary fuel used to power new electricity generating plants. Of the fossil fuels, natural gas produces less $CO_2$ than coal or oil and smaller amounts of nitrogen oxide ($NO_x$). In addition to electricity generation, natural gas is also used in residential, commercial, and industrial applications. The Southwest uses the largest percentage of natural gas to generate electricity.

- **Hydropower and Other Renewables** together produce nearly 11 percent of U.S. electricity. Hydropower's operational flexibility—its unique ability to change output quickly—is highly valued. Hydropower also produces no greenhouse gases or other air pollutants. The Pacific Northwest relies on hydroelectric power for a large percentage of its electricity needs.

  Using **non-hydropower renewable energy** sources, such as solar power, wind, geothermal, and biomass, to generate electricity produces minimal environmental impact. Certain renewable resources (wind and solar) represent inexhaustible, though intermittent, supplies of energy. These sources of energy currently supply less than one percent of U.S. electricity.

- **Oil-based** electricity generation offers many advantages as a peaking fuel. Oil's use, though, has declined steadily over the last two decades, decreasing by almost two-thirds since 1978. The Northeast and Alaska use the largest amounts of oil to generate electricity.

## Public policies can restrict fuel generation options.

The mix of fuels used to generate electricity has shifted dramatically over the past 20 years. Changes in government policies and regulatory practices have influenced many of these shifts. For example, in the late-1970's—during the midst of a worldwide oil embargo—new utility plants were prohibited from using natural gas or petroleum products to generate electricity. Instead, to meet demand, decisions were made to build more coal-based plants. Today, natural gas is re-emerging as the fuel of choice for new electricity generation.

Recent events—such as electricity price spikes, volatile foreign crude oil prices, higher gasoline prices, and rising natural gas and home heating oil prices—underscore that America is facing yet another energy challenge. As a result, changes in government policies are again likely. When addressing these new energy challenges, policymakers and regulators are asked to consider the following:

- **Coal**-based generators face a variety of environmental regulations aimed at reducing power plant air emissions. These include at least eleven regulatory programs affecting $NO_x$ controls and eight programs affecting sulfur dioxide ($SO_2$) emissions. In December 2000, the U.S. EPA issued a determination to regulate mercury emissions by 2004. EPA's proposed regulations to further restrict coal-based emissions can be duplicative, contradictory, complex, and unnecessarily costly, and create enormous uncertainty.

- **Nuclear** power's future in the U.S. remains uncertain despite its advantages as a source of electricity free of air emissions. High initial construction costs, operating and maintenance expenses, long lead times, and regulatory uncertainty for new plants restrict the utilization of this generation option. In addition, unresolved questions about how to dispose of low-level nuclear waste and spent fuel (high-level radioactive waste) from nuclear power plants constrain further utilization of this fuel source. Currently, spent fuel is being stored on-site at nuclear energy plants around the nation. Legislation to establish a permanent high-level waste storage facility has not been enacted.

  **Natural gas** is facing rapidly escalating demand both from the electricity sector and traditional end-use residential, commercial, and industrial customers. Regulatory policies—including siting and drilling limitations, delays in gaining rights-of-way for delivery systems, and restrictions on access to natural gas supplies on public lands—constrain natural gas supply and delivery.

  **Hydropower** projects, while not emitting air pollutants, have become a source of controversy with certain recreational users and environmental organizations. Owners and operators of hydropower projects face a federal relicensing process that has become very costly, time-consuming, and uncertain. Relicensing typically requires eight to ten years to complete, and federal legislation to streamline the relicensing process has been delayed. By 2010, 228 hydropower projects—accounting for nearly 19,000 megawatts of hydro capacity—will face relicensing. Federal legislation to streamline the relicensing process has been introduced but not enacted into law.

  Many **non-hydropower renewable energy** projects face the same siting hurdles encountered by other electricity generation facilities. Also, the costs for generating electricity from certain renewables remain high relative to other available fuels. Unlike most other fuels, many renewable energy sources, such as solar and wind, are intermittent—that is, not available at all times or not readily available if demand for electricity is required immediately. In addition, geothermal energy for electricity production is limited to a very few regions around the country. Electricity produced from biomass resources—unless the biomass is a waste product (timber, urban, animal, or agricultural waste)—will require vast quantities of land to replenish the fuel.

  While ongoing research, federal tax incentives, and the development of technologies to utilize renewable resources have reduced the costs to generate renewable electricity significantly, debate continues over how best to address the higher costs involved in the production of useful energy from renewables.

# ALASKA NATURAL GAS TRANSPORTATION SYSTEM

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## ISSUE PAPER NO. 1

**The Scope of the Alaska Natural Gas Transportation Act and its Continuing Authority Over the Development and Certification of Initial Transportation Facilities to Transport Natural Gas From the Alaska North Slope to Markets in the Lower 48 States**

February 2001


Prepared by: The Alaskan Northwest Natural Gas Transportation Company

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Washington: Curt Moffatt - (202) 298-1885
jcm@vnf.com

## FOREWORD

The Alaskan Northwest Natural Gas Transportation Company ("ANNGTC") is the partnership which holds the Federal Energy Regulatory Commission certificate of public convenience and necessity to construct, own and operate the Alaska component of the Alaska Natural Gas Transportation System (the "Alaska Highway Project"). Foothills Pipe Lines Ltd. ("Foothills") and TransCanada PipeLines Limited ("TransCanada") are the two current partners in the ANNGTC. In addition, Foothills is the sponsor of the Canadian segment of the Alaska Highway Project, and the majority owner and operator of the Canadian portions of the Eastern and Western Legs of the Project. Foothills is jointly owned by TransCanada and Westcoast Energy Ltd.

The corporate mission of Foothills is very specific: to build and operate the Alaska Highway Project. We were leaders in the Project that was conceived twenty-five years ago, and we are just as committed to it today.

Given concerns about high energy prices and the adequacy of natural gas supplies, interest in connecting Alaskan natural gas to markets in North America is being renewed. Of course, this is not a new issue. It is an issue that has dominated energy policy debates in the United States and Canada on and off for the last quarter century. There is much history in this story. Recognition of the importance of an Alaska gas project to both countries prompted action at the highest levels of government, including (1) Congressional action, embodied in the Alaska Natural Gas Transportation Act of 1976; (2) cooperation between the United States and Canada, as embodied in the 1977 Agreement Applicable to a Northern Natural Gas Pipeline; (3) Canada's enactment of the Northern Pipeline Act; and (4) the selection of the Alaska Highway Project in 1977 as the approved Alaska natural gas transportation system under these government acts.

During the current debate, questions understandably will arise regarding the history and context of the Alaska Highway Project. To facilitate the resolution of these issues, the ANNGTC and its partners will prepare from time to time Issue Papers that address emerging questions and provide a useful context within which to conduct the public policy and commercial debates.

Attached is one such Issue Paper. Please feel free to contact us for further information and/or to discuss the contents of this or other Issue Papers.

THE SCOPE OF THE ALASKA NATURAL GAS TRANSPORTATION ACT AND ITS CONTINUING AUTHORITY OVER THE DEVELOPMENT AND CERTIFICATION OF INITIAL TRANSPORTATION FACILITIES TO TRANSPORT NATURAL GAS FROM THE ALASKA NORTH SLOPE TO MARKETS IN THE LOWER 48 STATES

## I. Introduction and Background

The abrupt rise in the price of oil and natural gas that began in the late 1990s and intensified in 2000 and 2001 echoes the energy situation that confronted the nation in the mid-1970s. Rising natural gas prices and increased demand for limited continental natural gas supplies have sparked renewed interest in the completion of the Alaska Natural Gas Transportation System ("ANGTS"). The ANGTS was designated by President Carter in his decision as the nation's chosen instrument for facilitating the transportation of gas from Alaska's North Slope to domestic markets in the lower 48 states pursuant to unique designation procedures established in the Alaska Natural Gas Transportation Act of 1976 ("ANGTA").[1] Pursuant to the ANGTA, the President's choice was thereafter approved by Congress.[2] Since then, it has never been revoked or rescinded.

Although parts of the ANGTS–the Eastern Leg, running from a point on the Canadian border near Moncy, Saskatchewan to Dwight, Illinois, and part of the Western Leg, running from the British Columbia border to California–were constructed and placed in operation, construction of the Alaska segment of the project was postponed when energy prices dropped in the late 1970s and early 1980s, rendering the Alaska portion of the project uneconomic with financing difficult to obtain. Due to the delay in construction of the Alaska segment of the ANGTS until domestic markets could support the project, it recently has been suggested that the Federal Energy Regulatory Commission ("FERC") might consider alternatives to the ANGTS under section 7 of the Natural Gas Act ("NGA"). Section 7 of the NGA generally authorizes the FERC to issue certificates of public convenience and necessity for the construction or extension of facilities for the transportation of natural gas in interstate commerce.[3] The primary legislative purpose of ANGTA, to assure construction and initial operation of the selected transportation system, requires the conclusion that the FERC is prohibited from considering, under section 7 of the NGA, alternative systems to the ANGTS to provide for the transportation of Alaska North Slope natural gas to the lower 48 states until such time as that purpose is fulfilled.

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[1] Pub. L. 94-586, approved October 22, 1976, 90 Stat. 2903, as amended, 15 U.S.C. §§ 719-719o (1994).
[2] Joint Resolution of Congress, H.R.J. 621, Pub. L. No. 95-158, 91 Stat. 1268, 95th Cong., 1st Sess. (1977).
[3] 15 U.S.C § 717f.

## II. ANGTA Modified § 7 of the NGA

In enacting the ANGTA, Congress discarded the usual procedures of the NGA and, in their place, established a unique framework for designating and certifying a system to transport natural gas from Alaska's North Slope to the lower 48 states. In the mid-1970s, the Federal Power Commission ("FPC"), the predecessor to the FERC, was struggling to choose, under section 7 of the NGA, the best among three mutually exclusive projects. While agreeing with the FPC that known gas reserves and anticipated market demand in the lower 48 states would support the financing and construction of only one transportation system, Congress recognized that the FPC's complex procedures for choosing the most suitable proposal, and the likelihood of judicial challenges to the FPC's final decision, threatened to increase the cost for, and delay the delivery of, much-needed North Slope natural gas to American consumers.

In light of the urgent need to meet demand in the lower 48 states and to blunt rising energy prices, Congress enacted the ANGTA. The ANGTA superseded the NGA process and the then-pending multiple FPC proceedings to certificate a project to transport Alaska North Slope gas to markets in the lower 48 states. Instead, it empowered the President, subject to Congressional approval, to choose a single project under the ANGTA's unique procedures. In addition, the ANGTA set forth various requirements intended to ensure that the system selected would be completed and in initial operation before any other proposals for moving Alaska natural gas to markets in the lower 48 states could be considered under the usual provisions of the NGA.

Section 5 of the ANGTA specifically directed the FPC to suspend its pending comparative proceedings until either the President's decision took effect following congressional approval or no such decision took effect (either because Congress withheld its approval or the President decided not to designate a system). Once Congress approved the President's Decision, the FPC was then directed to vacate the suspended proceedings and to issue, in accordance with the President's Decision, a certificate of public convenience and necessity for the designated system and its sponsors. Under section 5, only if the President made no designation, or if the President's designation never became effective because it was not approved by Congress, could the certification of an initial Alaska natural gas transportation system thereafter be made under the normal NGA procedures.

The ANGTA also required expedition and precedence for processing needed permits and authorizations such as rights-of-way in order to facilitate construction and initial operation. Specifically, section 9 of the ANGTA provided that no condition in any certificate or permit related to the construction or initial operation of the approved system and no amendment or abrogation of any such term or condition could change the basic nature and general route of the approved system, or otherwise prevent or impair, in any significant respect, its expeditious construction and initial operation.

# ALASKA NATURAL GAS TRANSPORTATION SYSTEM

# ISSUE PAPER NO. 2

**Authority of the Federal Energy Regulatory Commission to Amend the ANNGTC's Certificate of Public Convenience and Necessity**

**February 2001**

Prepared by: The Alaskan Northwest Natural Gas Transportation Company

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Washington: Curt Moffatt - (202) 298-1885
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## FOREWORD

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During the current debate, questions understandably will arise regarding the history and context of the Alaska Highway Project. To facilitate the resolution of these issues, the ANNGTC and its partners will prepare from time to time Issue Papers that address emerging questions and provide a useful context within which to conduct the public policy and commercial debates.

Attached is one such Issue Paper. Please feel free to contact us for further information and/or to discuss the contents of this or other Issue Papers.

# AUTHORITY OF THE FEDERAL ENERGY REGULATORY COMMISSION TO AMEND THE ANNGTC'S CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

## I. Introduction and Background

This paper addresses the extent to which the Federal Energy Regulatory Commission ("FERC" or "Commission") has the authority to amend the conditional certificate of public convenience and necessity authorizing the Alaskan Northwest Natural Gas Transportation Company ("ANNGTC") to construct and operate the Alaska segment of the natural gas transportation system approved by Congress under the Alaska Natural Gas Transportation Act ("ANGTA").[1] This paper concludes that the statute provides broad authority to add to, amend or abrogate prior decisions so long as there is not a change to the "basic nature and general route" of the system and the change does not compel a significant delay in the construction or initial operation of the system.

When Congress passed ANGTA in 1976, it recognized that the selection of a system to transport Alaska gas to the lower 48 states involves "questions of the utmost importance respecting national energy policy, international relations, national security, and economic and environmental impact . . . ."[2] Because of the importance of these issues, Congress decided that they "should appropriately be addressed by the Congress and the President in addition to those Federal officers and agencies assigned functions under law pertaining to the selection, construction, and initial operation of such a system."[3] The stated purpose of ANGTA "is to provide the means for making a sound decision as to the selection of a transportation system for delivery of Alaska natural gas to the contiguous United States . . . by providing for the participation of the President and the Congress in the selection process," and, if a system is approved under the Act, "to expedite its construction and initial operation . . . ."[4]

## II. Alcan Project Selected as the Approved Alaska Natural Gas Transportation System

### A. ANGTA Section 5 and the FPC's Recommendation to the President

ANGTA established specific procedures to govern the application of the Natural Gas Act and the implementing regulations of the Federal Power Commission ("FPC") and FERC. Section 5 of ANGTA gave the FPC approximately six months to consider the competing applications for authorization to construct an Alaska gas transportation system, and to submit a recommendation to the President as to which project, if any, should be selected. Although Section 5 of ANGTA listed factors that the FPC was to consider in making its recommendation to the President, it did not prohibit changes in the project as proposed by project sponsors. ANGTA simply required the Commission to describe "the nature and the route" of the recommended project. It did not require the Commission to determine each detail of the project.

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[1] Pub. L. 94-586, approved October 22, 1976, 90 Stat. 2903, as amended, 15 U.S.C. §§ 719-719o (1994).
[2] ANGTA § 2(1) & (4).
[3] *Id.*
[4] ANGTA § 3.

In accordance with Section 5 of ANGTA, the FPC submitted its Recommendation to the President by letter dated May 2, 1977.[5] The FPC also submitted an extensive report accompanying its Recommendation that compared three competing proposals: (i) a Canadian Arctic Gas overland project, (ii) an El Paso Alaska LNG project, and (iii) two alternative projects proposed by Alcan: the Alcan I 42-inch pipeline project and the Alcan II 48-inch pipeline project.[6]

The FPC concluded that the President should select an overland route. However, it split 2-2 on which of the two proposed overland routes was superior: the Arctic Gas project (which would traverse the Mackenzie Delta in Canada, thus allowing immediate access to Mackenzie gas), or the Alcan II 48-inch pipeline project (which would provide for future access to Mackenzie gas via a separate project that would connect with the Alcan II project).[7] The Commissioners concluded by stating: "In the absence of a Canadian determination that development and transportation of Mackenzie reserves should be permitted, the Alcan Project should be approved, subject to the Government of Canada's making the route available on acceptable terms and conditions."[8]

While the FPC based its conclusion on "the massive record" compiled in the proceeding, none of the FPC's conclusions referenced the specifics of the projects' proposed design or required the proposed projects to remain unaltered from those initially proposed by the project sponsors. The FPC focused on the relative effects of numerous factors on the environmental and economic impact of each proposal. Moreover, in its Recommendation, the FPC expressly recognized that "*final plans for design and construction are not yet developed.*"[9] Accordingly, the Commission's Recommendation to the President did not foreclose an amendment to the ANNGTC's Certificate that would change the design or configuration of the Alcan project as originally proposed as long as it does not change the basic nature and general route or significantly delay expeditious construction and initial operation.

**B. ANGTA Section 7 and the President's Decision**

After other jurisdictional agencies submitted to the President their comments on the FPC's recommendation,[10] Section 7(a)(1) of ANGTA gave the President three months to issue a decision as to whether a transportation system should be built and, if so, which one. If the President decided to designate a transportation system for approval by Congress, Section 7(a)(1) required the decision "to be based on his determination as to which system, if any, best serves

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[5] Federal Power Commission, *Recommendation to the President: Alaska Natural Gas Transportation Systems* (May 1, 1977) ("FPC Recommendation").
[6] In discussing each project, the FPC addressed matters such as gas reserves and availability, net national economic benefits, cost of service, expandability, environmental impacts, geotechnical problems and reliability, construction costs and scheduling, and financing and tariffs.
[7] Transmittal Letter at 2. The Commissioners' disagreement apparently was based on uncertainty regarding authorizations to be issued by the Canadian Government with respect to the Mackenzie gas.
[8] *Id.* References in the FPC's Recommendation to approval of the "Alcan project" refer to the Alcan II 48-inch pipeline project.
[9] FPC Recommendation at I-38 (emphasis added).
[10] *See* ANGTA § 6.

the national interest."[11] Section 7(a)(4)(A)-(D) required the President to make four specific determinations in his decision:

- To "describe the nature and route of the system designated for approval . . . .";

- To "designate the person to construct and operate such a system, which person shall be the applicant . . . which filed for a certificate of public convenience and necessity to construct and operate such system . . . ";

- To "identify those facilities, the construction of which, and the operations, the conduct of which, shall be encompassed within the term 'construction and initial operation' for purposes of defining the scope of the directions contained in section 9 of this Act," *i.e.*, directions to jurisdictional agencies with respect to expediting the construction and initial operation of the facilities; and

- To identify "those provisions of law . . . which provisions the President finds requires waiver pursuant to section 8(g) in order to permit expeditious construction and initial operation of the transportation system."[12]

By letter dated September 22, 1977, President Carter forwarded to Congress his Decision and report in which he selected the Alcan project as the Alaska Natural Gas Transportation System ("ANGTS"). In the Overview to his Decision, the President recounted events that led up to his Decision, most notably, the conditional approval by Canada's National Energy Board ("NEB") of the Canadian segments of the Alcan project and the signing of the Agreement on Principles.[13] In fact, the President incorporated the U.S.-Canada Agreement on Principles as Section 7 of his Decision.[14] The President's conclusion more than twenty-three years ago is equally applicable today:

> A superior project has now been selected as a result of a thorough decisionmaking process involving all the resources of the Federal Government and a spirited competition between private alternatives. The nation sorely needs new resources of economically competitive natural gas. Now is clearly the time to approve the decision to undertake the final planning and construction of this cost-effective system for bringing critical supplies of Alaska natural gas to U.S. markets.[15]

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[11] ANGTA § 7(a)(1).

[12] ANGTA §§ 7(a)(4)(A)-(D). Section 7(c) also required the President to include in his report a financial analysis of the transportation system designated for approval, for purposes of determining whether the system could be privately financed or would require Federal financing authority.

[13] President's Decision at pp. v-vii.

[14] The President observed that the Agreement on Principles "provides the framework for a clearly specified, economically efficient, and environmentally superior means of transporting both U.S. and Canadian gas to markets through a joint pipeline system." President's Decision at vii.

[15] President's Decision at xiv.

Structurally, the President's Decision mirrors the structure of ANGTA itself. The first four sections of the President's Decision correspond to the four conclusions required of the President by ANGTA Sections 7(a)(4)(A)-(D).

1. **Section 2 of the President's Decision: The Nature and General Route of the Approved System**

To comply with Section 7(a)(4)(A) of ANGTA, Section 2 of the President's Decision described the "Nature And Route Of The Approved System." The general, two-paragraph description of the approved system in Section 2 describes the "basic nature" of the approved transportation system and the remainder of Section 2 describes the "general route" of the ANGTS for purposes of implementing the various procedures specified in Section 9 of the Act.

Section 2 described the *nature* of the system in two short paragraphs:

> The Alcan system is an overland pipeline system to transport natural gas from the Prudhoe Bay area of Northern Alaska through Alaska and Canada into the Midwest and Western sections of the contiguous United States.
>
> The expected volume of gas to be available initially from the Prudhoe Bay field is 2.0 to 2.5 billion cubic feet per day (bcfd). The system described herein is designed to handle this throughput volume. The capacity of the system could be increased in the future to accommodate additional volume throughput by construction of additional facilities.[16]

The remainder of Section 2 described in some detail (in thirteen paragraphs and two maps) the *route* of the pipeline in Alaska, Canada, and the contiguous United States.[17]

2. **Section 3 of the President's Decision: "Identification of Facilities Included Within 'Construction and Initial Operation'"**

Section 3 of the President's Decision is titled "Identification of Facilities Included Within 'Construction and Initial Operation.'" It complied with Section 7(a)(4)(C) of ANGTA, which required the President to:

> . . . identify those facilities, the construction of which, and those operations, the conduct of which, shall be encompassed within the term "*construction and initial operation*" for purposes of defining the scope of the directions contained in section 9 of this Act, taking into consideration any recommendation of the Commission with respect thereto . . . .[18]

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[16] President's Decision at 6 (reference omitted).
[17] President's Decision at 6-11.
[18] ANGTA § 7(a)(4)(C) (emphasis added).

The President stated that Section 3 of his Decision "identifies the facilities for the Alcan project which will be entitled to the expedited authorization process prescribed in Section 9 of ANGTA"[19] – for example, pipeline diameter, the length of pipeline segments, and the location and horsepower of compressor stations.

In the General Project Description subsection, the President indicated that the facilities described in Alcan's March 8, 1977 filing, as well as any modifications in those facilities required by the Agreement on Principles, would be accorded Section 9's expedited procedures. *Both Alcan's March 8, 1977 filing and the Agreement on Principles recognized that significant changes would be made in the project after it was selected by the President and approved by Congress.*

Thus, Section 3 of the Decision is distinguishable from the description of the "basic nature and general route" of the approved pipeline system as set forth in Section 2. Section 3 responds to the requirements of ANGTA Section 7(a)(4)(C) and identifies facilities to be afforded expedited regulatory review in accordance with Section 9 of ANGTA. Section 3 of the Decision neither dictates the design or configuration of the facilities identified therein, nor prohibits the Commission from modifying or adding additional facilities under the expedited procedures of Section 9 of ANGTA.

**C. ANGTA Section 8: Congress Approves the Alcan Project**

On November 2, 1977,[20] Congress issued a joint resolution adopting the President's Decision and the President signed the Joint Resolution into law on November 8, 1977. Today, the Alcan project remains the "approved transportation system" for purposes of Section 9 of ANGTA.

**D. ANGTA Section 9: FERC Issues Certificate**

By order issued December 16, 1977, the Commission issued conditional certificates of public convenience and necessity to the project sponsors under Section 7 of the Natural Gas Act and ANGTA.[21] In its order, the Commission noted that its action issuing conditional certificates under ANGTA "are ministerial actions which the Commission must perform without any exercise of administrative judgment or discretion."[22] The Commission expressly noted the need for further data before it could take final action, stating, "the Alcan Pipeline Project is at too incipient a stage to warrant Commission acceptance of applications of permanent certificates of public convenience and necessity." The Commission further stated that it viewed its action "as a step which initiates the detailed process of final certification."[23]

The Commission expressly listed matters that would require "substantial inquiry," such as "gas reserves and deliverability, . . . wellhead price . . ., financial plan . . ., shippers' tariffs . .

[19] President's Decision at 13.
[20] Joint Resolution of Congress, H.R.J. 621, Pub. L. No. 95-158, 91 Stat. 1268, 95th Cong., 1st Sess. (1977).
[21] 1 FERC ¶ 61,248 (1977).
[22] *Id.* at 61,641.
[23] *Id.*

., pipe selection (*choice of diameter and pressure*), and size and volume of the Eastern and Western Legs."[24] Accordingly, neither the Commission's order nor the conditional Certificate limited the project sponsors' ability to modify aspects of the design, facilities, financing plans and/or tariffs.

## III. ANGTA Section 9 and FERC Authorization to Amend the ANNGTC Certificate

Section 9 of ANGTA is addressed to all federal officers and agencies – including the FERC – that issue certificates, rights-of-way, permits, leases or other authorizations required for "the taking of any action which is necessary or related to the construction and initial operation of the approved project." Section 9(a) directs the covered federal officers and agencies to "issue or grant such certificates . . . and other authorizations" required for the construction and initial operation of the ANGTS "at the earliest practicable date" and to the "fullest extent" permitted by law. Moreover, Section 9(b) directs the covered federal officers and agencies to expedite "all actions . . . with respect to its consideration of applications or requests" for such authorizations, giving them "precedence over any similar applications or requests . . . ."

With respect to certificates or other authorizations already issued to the ANNGTC, *Section 9(d) expressly authorizes the issuing agencies or officers to "add to, amend or abrogate any term or condition included in such certificate . . . or other authorization . . . ."* However, such entities including the Commission, "shall have no authority to take such action if the terms and conditions to be added, or as amended, *would compel a change in the basic nature and general route* of the approved transportation system or would *otherwise prevent or impair in any significant respect the expeditious construction and initial operation of such transportation system*," unless such terms and conditions are required by law. (Emphasis added).

Under Section 9, therefore, the FERC must approve the ANNGTC's Certificate amendment to the fullest extent otherwise permitted by law, must expedite any action related to the certificate amendment, and must give that action precedence over any similar application – unless such action would "compel a change in the basic nature and general route of the [ANGTS] or would otherwise prevent or impair in any significant respect the expeditious construction and initial operation of such transportation system."

The "basic nature and general route" of the ANGTS, as that term is used in Section 9, is derived from Section 2 of the President's Decision. As discussed in part II.B.2 above, Section 3 of the President's Decision identified facilities included in the ANGTA term "*construction and initial operation*" for purposes of defining the scope of the directions contained in section 9 of ANGTA, which provisions include FERC's powers to condition certificates (Section 9(c)) and to amend certificates (Section 9(d)). Section 2 of the President's Decision described the "nature and route" of the approved system. It summarized the nature of the system as "an overland pipeline system to transport natural gas from the Prudhoe Bay area of Northern Alaska through Alaska and Canada into the Midwest and Western sections of the Contiguous United States." This language describes the "basic" nature of the transportation system approved by the President.

[24] *Id.* at 61,642 (emphasis added).

As required by ANGTA Section 7(a)(4)(C), Section 3 of the President's Decision identified the "facilities" that "shall be encompassed within the term 'construction and initial operation' for purposes of defining the *scope* of the directions contained in Section 9" of ANGTA. (Emphasis added). Thus, Section 3 provided that the *scope* of Section 9's directions to federal authorities to expedite agency action would extend to pipelines, compressors, and metering facilities, as well as the location of operating centers, staging areas, material storage sites, and transportation and communication facilities, and the other facilities described in Section 3. Neither Section 7(a)(4)(C) of ANGTA nor Section 3 of the President's Decision restricted the Commission's authority to consider *changes* to those facilities. Rather, Congress specifically defined that authority in Section 9(d) of ANGTA.

Further, when Congress approved the President's proposed Waiver of Law in 1981 to add the gas conditioning plant to the system, it did so by approving an amendment to Section 2 of the President's Decision, not to Section 3. In this regard, the President's Findings and Proposed Waiver asked Congress to waive Public Law 95-158 (Congress' 1976 Joint Resolution incorporating and approving the President's Decision) "in the following particulars," including "Section 2, Paragraph 3, First Sentence, of the President's Decision, to include the gas conditioning plant in the *approved transportation system* and in the final certificate to be issued for the system . . . ."[25] Section 3 was not amended to include the gas conditioning plant. The President instead left that process for the FERC to address by amendment under Section 9(d) of ANGTA.

In approving this Waiver of Law, Congress recognized the importance of the conditioning plant to the overall system. As stated in the report of one jurisdictional committee:

> The Committee approves this segment of the waiver package because of the enormous size and capital cost of the facility. To withhold the gas conditioning plant from inclusion as part of the system could jeopardize the entire project. It should be noted that the granting of the waiver will make it eligible for consumer financing through the early billing commencement provisions of the waiver, for guarantees that costs will be passed through shippers to consumer[s], and for other "regulatory certainty" provisions in the waiver package.[26]

By amending Section 2 of the President's Decision to include the conditioning plant, Congress assured that the plant would be included in the "approved transportation system," that is, that the plant would be included in the "basic nature and general route" of the ANGTS. Because the description of "basic nature and general route" included in Section 2 of the President's Decision is what defines that same term as used in Section 9 of ANGTA, the inclusion of the plant in Section 2 allowed FERC to make an amendment to the certificate using Section 9(d). Moreover, the FERC's consideration of such amendment under the expedited procedures required under

[25] Waivers to Permit Expedited Construction of the Alaska Natural Gas Transportation System, 97th Cong., 1st Sess., House Document No. 97-100, p. 2 (Oct. 15, 1981) (emphasis added).
[26] U.S. House of Representatives Report, 97-350, part 1, Committee on Interior and Insular Affairs, p. 22 (Nov. 20, 1981).

Sections 9(a) and (b) of ANGTA would facilitate, not prevent or impair, the expeditious construction and initial operation of the project. And that is exactly what FERC did regarding the conditioning plant.

## IV. Changes to the Design of ANGTS Are Authorized Under ANGTA

Section 9 of ANGTA expressly authorizes the FERC to amend the ANNGTC's Certificate if such amendment would not compel a change in the basic nature or general route of the system as approved in Section 2 of the President's Decision. As a general matter, the modification of facilities specifically described in Section 3 of the President's Decision would not necessarily change the basic nature or general route of the approved system. Under ANGTA Section 9, however, the ANNGTC will have to demonstrate that the kinds of modifications that it proposes would not compel a change in the basic nature or general route of the approved pipeline system under Section 2 of the President's Decision and would therefore be an appropriate amendment under Section 9(d).

The ANNGTC is currently evaluating technical changes to the ANGTS facilities to modernize the project to meet today's market conditions, such as with changes to pipeline diameter and pressure from that proposed in Alcan II. Any modifications proposed by the ANNGTC will improve the economic efficiency, safety and environmental impact of the ANGTS. Such changes in the technical design of the pipeline would not amend the "basic nature" of the ANGTS described in Section 2 of the President's Decision, *i.e.*, an overland pipeline system that transports natural gas from Prudhoe Bay through Alaska and Canada into the Western and Midwestern sections of the United States, with sufficient capacity to handle the volumes of gas expected to be available initially from the Prudhoe Bay field, and capable of expansion to handle additional volumes. Because approval of the pipeline design and specifications proposed by the ANNGTC would not compel a change in this "basic nature" of the approved project, Section 9(d) of ANGTA would expressly authorize the Commission to amend the ANNGTC's Certificate accordingly.[27]

ANNGTC is mindful of the prohibition in Section 9(d) of an amendment of the Certificate that would "otherwise prevent or impair in any significant respect the expeditious construction and operation" of the ANGTS. To the extent that advanced, more efficient, and safer pipeline construction technology and operation present new opportunities which must be field tested, such testing was an integral component of the FPC's Recommendation and the

[27] As discussed in Section IV(C)(2)(b) of this memorandum, Section 10 of the Agreement on Principles provided for a bilateral technical study group to determine the appropriate diameter and pressure of the ANGTS to efficiently accommodate Mackenzie gas. The Agreement on Principles is still in effect, the Canadian and Alaskan segments addressed in Section 10 of the Agreement have not been constructed, and the development and transportation of Mackenzie reserves is still an issue of concern in Canada. It may be necessary, therefore, to convene a new study group under Section 10 of the Agreement to consider the appropriate system design necessary to "achieve safety, reliability and economic efficiency for operation of the Pipeline," under modern technologies and operating practices. Under this approach, Section 3 of the President's Decision expressly would include any resulting modifications in project design among the facilities covered by the expedited procedures of Section 9 of ANGTA.

President's Decision to ensure that ANGTS would consist of modern, efficient, and safe technologies. The Commission would be authorized to consider to apply the same public interest considerations to evaluate changes in reference to today's marketplace.

Additional changes that the ANNGTC is considering involve technical modifications of the pipeline configuration, the design of the Alaska Gas Conditioning Facility and improvements to the Net National Economic Benefit. Such changes will be proposed in a manner consistent with Section 9 of ANGTA to ensure they do not alter the basic nature and general route of the approved ANGTS project.

Changes to the technical nature of the ANGTS have been an integral part of the ANGTA process from the beginning. For example, Alcan's March 8, 1977 filing contemplated that the original system it proposed would be changed. In addition, the Agreement on Principles contemplated changes in pipeline size and pressure and directed a technical study group to address potential modifications to the approved project. The 1981 Waiver of Law also implemented changes to the ANGTS facilities, and provides an illustrative example of the type of changes that require amending the basic nature and general route of the ANGTS.

## V. Conclusion

Whether the Commission can amend the ANNGTC's Certificate to approve the modifications in pipeline design and specifications, pipeline configuration, and conditioning plant which may be proposed by the ANNGTC under the expedited procedures required by Section 9 of ANGTA depends on whether such changes modify Section 2 of the President's Decision and constitute changes in the "basic nature" or "general route" of the project within the meaning of Section 9.

The answer to this question is that where the project, as revised, will have the same *basic* nature and *general* route – i.e., it is still an overland pipeline system capable of transporting natural gas from Prudhoe Bay through Alaska and Canada into the Midwest and Western sections of the contiguous United States – such changes will be within the expedited review process of Section 9.

In addition, as reflected repeatedly in the FPC's Recommendation to the President, the Agreement on Principles, and the President's Decision, the design and configuration of the Alcan Project was far from being finalized at the time the project was approved by the President. As the example of the AGCF modifications illustrate, it is unreasonable to conclude that Congress intended to prohibit the Commission from modifying the project's design and configuration to achieve a superior system – provided that the basic nature and general route of the system remain unchanged.

Although neither ANGTA nor the President's Decision expressly defines the phrase "basic nature and general route" as used in Section 9, the most credible construction of Sections 2 and 3 of the President's Decision — when read together with Sections 7 and 9 of ANGTA — concludes that the broad description of the nature and route of the ANGTS in Section 2 defines the "basic nature and general route" for purposes of Section 9 of ANGTA.

It is apparent that modifications to the design and configuration of the Alaska segment currently being contemplated by the ANNGTC are not only related, but necessary, to the construction and initial operation of the Alaska segment under modern technology, operating practices, and market conditions.

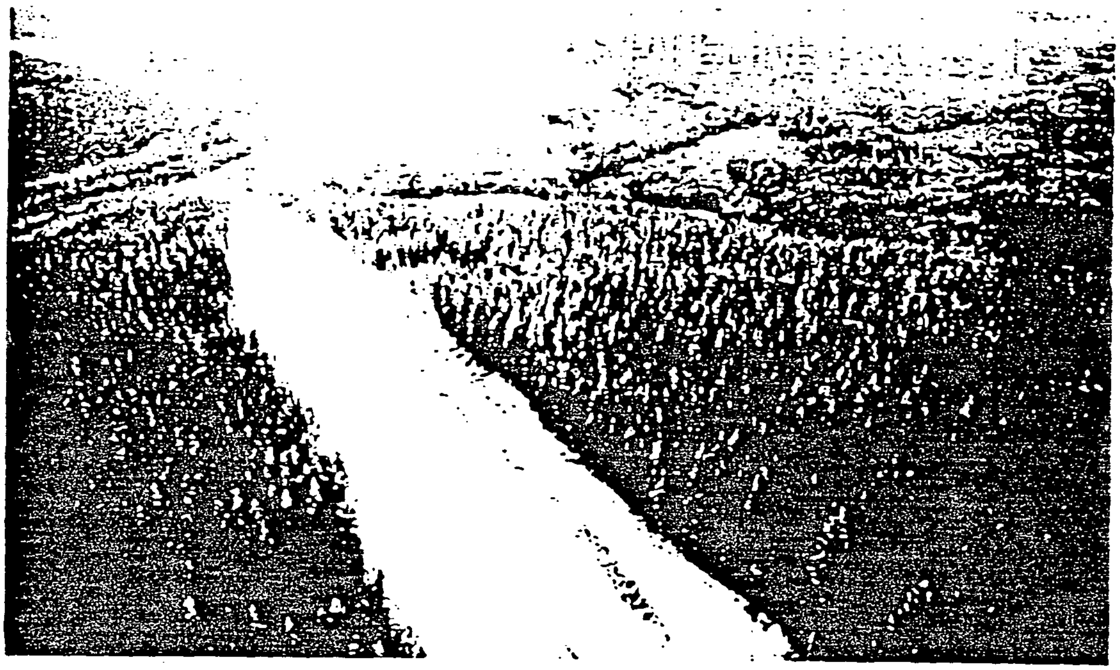
Moreover, both the U.S. and Canadian governments remain bound by the Agreement on Principles, which has the force and effect of a treaty between the two nations. The Agreement obligates both nations to take "all necessary action" to "authorize the construction and operation of the Pipeline in accordance with the principles set out" in the Agreement.[28]

The Commission therefore is bound to consider any of ANNGTC's proposed modifications that are consistent with Section 2 of the President's Decision pursuant to the expedited procedures of ANGTA Section 9. In addition, to the extent necessary, the President is also bound to take "all necessary action" to enable the Commission to proceed expeditiously with the authorizations required for the completion of the ANGTS as required by the Agreement on Principles which could include a request from the President to the Congress to waive any provisions of law pursuant to Section 8(g) of ANGTA.

[28] Agreement on Principles, § 1.

ALASKA SENATE LEGISLATURE

# Senate Resources Committee



February 5, 2001

Presentation by

John Ellwood
Vice President, Engineering & Operations

Foothills Pipe Lines Ltd.

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## Foothills Pipe Lines Ltd. / Alaska Highway Gas Pipeline Project

My name is John Ellwood. I am Vice President, Engineering and Operations at Foothills Pipe Lines Ltd. ("Foothills"). We appreciate your invitation to discuss the transportation of Alaska North Slope natural gas to markets in the lower-48 states through the Alaska Natural Gas Transportation System ("Alaska Highway Project"). I understand that your committee wishes to explore with us the current status of our pipeline project with a particular focus on our permits.

Let me begin by telling you about Foothills. Our company is jointly owned by Westcoast Energy Ltd. ("Westcoast") and TransCanada PipeLines Limited. ("TransCanada"), the two major players in the Canadian gas pipeline business. Our corporate mission is very specific: to build and operate the Alaska Highway Pipeline Project. We were leaders in the project that was conceived twenty-five years ago, and we are just as committed today.

Between Westcoast and TransCanada, we have nearly 100 years of experience in developing, building and operating gas pipeline projects. We have been involved with every major Canadian gas pipeline project built in the last fifteen years.

Our existing pipeline systems provide access to five of North America's largest natural gas markets. Together, these systems have the capability to move fifteen billion cubic feet per day of gas from Western Canada to the consuming markets. Canadian gas accounts for almost 20% of all gas consumed in the United States and all of that gas currently moves through pipelines owned in whole or in part by TransCanada and Westcoast.

This map shows the existing and planned pipeline network of Westcoast and TransCanada.

TransCanada, Westcoast and Foothills have developed leading edge gas pipeline design, construction and operating technology, including expertise in dense phase designs. We are also well known for our development of environmentally sound design, construction and operation practices. We believe that our expertise in northern, remote and difficult terrain gas pipeline construction and operations is second to none.

Building and operating pipelines is our core business.

The Alaska Highway Project is the Alaskan gas pipeline project approved in accordance with the Alaska Natural Gas Transportation Act of 1976 ("ANGTA") in the U.S., the 1978 Northern Pipeline Act in Canada, and the 1977 Agreement Applicable to a Northern Natural Gas Pipeline between the two countries ("U.S./Canada Agreement"). The project is shown in black and green on this map. As approved, the Alaska Highway Project is a 4,800-mile international pipeline project commencing at Prudhoe Bay and terminating in the Midwest and California market areas. It is important to note that the southern part of this pipeline has been constructed and is in full operation. The route for this system parallels the Trans Alaska Pipeline System ("TAPS") to Fairbanks, where it angles southeast, following the Alcan Highway to the Alaska-Yukon border with Canada, down through the Yukon Territory and northern British Columbia, and into Alberta. In Alberta, the pipeline splits into two legs. The Eastern Leg proceeds southwest, crossing the U.S.-Canada border at Monchy, Saskatchewan and terminating near Chicago. The Western Leg proceeds southwest, crossing the U.S.-Canada border near Kingsgate, British Columbia and terminating at a point near San Francisco, California.

Foothills and TransCanada are the two remaining partners of the Alaska Northwest Natural Gas Transportation Company (Alaska Northwest), a partnership formed to construct and operate the Alaska portion of the Alaska Highway Project. In addition, Foothills is the Canadian sponsor of the Alaska Highway Project, and the majority owner and operator of the Canadian portions of the Eastern and Western Legs of the Alaska Highway Project.

Foothills has continuously championed the Alaska Highway Pipeline Project from the very beginning.

The Project is back **"on the list"** of possible solutions to the current North American concerns about high energy prices and the adequacy of natural gas supplies.

At the outset, there are some basic points that we should delineate:

- It is important to remember that this pipeline crosses the territory of two countries with different regulatory and political regimes.

- The Project has a long history, which adds unique attributes. The permits which have been issued are a product of this history and to understand the former requires an appreciation of the latter. Significantly, ANGTA in the U.S. and the Northern Pipeline Act in Canada create expedited procedures for completing the chosen system, the Alaska Highway Project.

- The pipeline permitting process can be very time consuming. In addition to the substantial work already completed on both the Alaskan and Canadian portions of the Alaska Highway Project, the special legislative and regulatory procedures in place in the U.S. and Canada will assist in expediting the construction and initial operation of the Project and keeping unnecessary delays to a minimum.

**Historical Background**

As I indicated, there are important historical dimensions associated with this project. We might focus on the time frame 1976-1982. Originally there were three competing Alaskan natural gas pipelines proposed. As shown on this map two of the projects were overland pipelines through Alaska and Canada. The third project would have transported gas by pipeline to tidewater, following the route of the"TAPS" pipeline, where the gas would be liquefied and transported to California by liquefied natural gas ("LNG") tankers.

The U.S Congress enacted the Alaska Natural Gas Transportation Act of 1976 with a purpose to provide an expedited process with respect to the selection of a single transportation system for the delivery of Alaska natural gas to the lower forty-eight states and to expedite construction and initial operation of the chosen transportation system.

With respect to the transportation of Alaska North Slope gas to markets in the lower 48 states, ANGTA superseded the usual Natural Gas Act ("NGA") process for granting Federal regulatory authorization to construct and operate a pipeline. ANGTA assigned the responsibility for the overall Alaska pipeline agenda to the President and Congress. Much the same approach was followed in Canada, where the Government took an active role in the decision regarding the Alaska natural gas pipeline. The reason for the creation of this extraordinary authority was that the governments wanted to expedite a cumbersome regulatory approval process in order to move more quickly to a solution.

Prior to 1978, a Canadian Board of Inquiry (The Berger Inquiry) examined a proposal to move Alaska gas across the North Slope and along the Mackenzie Valley. At the same time the National Energy Board ("NEB") held a hearing to determine which of the two overland pipeline routes was acceptable to Canada. Both processes rejected the North Slope route (primarily for environmental reasons) and the NEB recommended the Alaska Highway (Alaska Highway Project) option, being promoted by Foothills. The Berger Inquiry recommended that no pipeline should be built along the Mackenzie Valley for at least a decade and that a pipeline across the northern Yukon should never be built.

During this same period of time the Federal Power Commission (later to become the Federal Energy Regulatory Commission ("FERC") came to a split decision on the question of which route should be selected.

Following the enactment of the ANGTA, the President selected the Alaska Highway route and the Alaska Highway Project with his <u>Decision and Report to Congress on the Alaska Natural Gas Transportation System</u> ("President's Decision" or "Decision").

In 1977 just prior to the President issuing his Decision, the U.S. and Canada signed the U.S./Canada Agreement. This agreement or treaty, established the route, chose the companies who would build and operate the system, established tolling principles, and set the terms and principles to be followed in facilitating the construction and operation of the Alaska Highway Project pipeline. The President's Decision reflected the U.S./Canada Agreement. The Decision and the Agreement were subsequently approved by the U.S. Congress.

In 1978 Canadian Parliament enacted the Northern Pipeline Act. The Act:

1) incorporated all of the terms of the U.S./Canada Agreement

2) issued **statutorv certificates** of public convenience and necessity to the respective subsidiaries of Foothills Pipe Lines Ltd.,
3) created the Northern Pipeline Agency to "*facilitate the efficient and expeditious planning and construction of the pipeline*

4) established the methodology and rules for setting the Canadian tolls and tariffs for the pipeline

5) selected the route for the pipeline across Canada and

6) established Terms and Conditions respecting the socio-economic, environmental, construction and operations matters.

The complete Alaska Highway Project is shown on the attached map.

The President's Decision designated Alcan Pipeline, a subsidiary of Northwest Pipeline Company (Northwest), as the party who would construct and operate the Alaska pipeline segment of the Alaska Highway Project. This authority was later assigned to Alaska Northwest, a partnership assembled by Northwest. At one time Alaska Northwest consisted of eleven (11) partners, all subsidiaries of U.S. or Canadian pipeline companies.

Given the magnitude of the pipeline undertaking Alaska Northwest sought to recruit the North Slope Producers to join the project and assist the financing of the pipeline. The Producers expressed a willingness to join but were restricted by the President's Decision that disallowed the producers taking an equity position in the pipeline. In 1981, President Reagan submitted and Congress approved a Waiver of Law package allowing producer participation and including in the project, the North Slope gas conditioning facility.

In 1980, before the Waiver of Law was passed, Alaska Northwest and the Alaska Producers entered into a Cooperation Agreement providing for joint funding of the design and engineering of the Alaska Highway pipeline and the gas conditioning facility. Following the approval of the Waiver of Law, the scope of the Cooperation Agreement was expanded to encompass efforts to achieve the remaining regulatory approvals and to jointly pursue financing arrangements. The two sides anticipated that affiliates of the Producers would join the Alaska Northwest Partnership.

Design, engineering, environmental, financing and regulatory work proceeded along parallel tracks in Alaska and in Canada during this period of time.

As world wide energy supply and demand came back into balance and the "energy crisis" eased, the focus of the pipeline shifted to the pre-building of the southern portions of the Alaska Highway Project. There was a disagreement between Canada and the United States over this issue, primarily as it related to the export of Canadian natural gas to the U.S. market.

The Canadian Government was unwilling to authorize the Pre-build or the gas exports without further assurance from the United States that the entire Alaska Highway Project, including the Alaska segment, would eventually be completed. This assurance was forthcoming in a letter from President Carter to Prime Minister Trudeau, along with a Congressional resolution. As a result the southern Pre-build pipeline section was completed by 1982. This involved constructing 650 miles of 36 and 42 inch pipeline from Caroline, Alberta to Monchy and Kingsgate on the US border. The Pre-build and subsequent expansions were constructed pursuant to the Northern Pipeline Act and it's regulatory regime managed by the Northern Pipeline Agency.

When the Pre-build construction began it was widely anticipated that North American natural gas demand would quickly resume its upward trend. However the market did not recover as anticipated and demobilization of the Alaska Highway Project soon began.

In order to remobilize, we will be required to make modifications and enhancements to various elements of the Alaska Highway Project regime. Pipeline designs will have to be modified so that that the Project can respond to capacity and gas quality requirements of the shippers. We will have to incorporate the latest technology and techniques necessary to ensure that the maximum environmental protection measures are in place. We do not expect any difficulty in introducing these revisions which are so obviously of benefit to all parties.

Recently other parties have raised issues related to payments that might be due to withdrawn partners pursuant to the Alaska Northwest Partnership Agreement. We are confident that if any return of the withdrawn partners' original investment is required it can be resolved within the context of an economically viable project.

Clearly there is a lot of work still to be done. It is very important to understand is that the advantages that come with the unique ANGTA and NPA regulatory regimes far outweigh the alternative of starting from scratch. Using the existing statutes and treaty we can assist in having Alaska natural gas into the U.S. market sooner, with competitive transportation costs and at the same time reducing project risks for all stakeholders.

In our capacity as the managing partner of Alaska Northwest we have maintained the Alaska Highway Project in good standing. We have kept the project alive to ensure that the advantages and benefits of the Project could be used in remobilization plans to expedite construction of the pipeline. We particularly wished to preserve what we see as the "special and unique fast track" regulatory regime.

Foothills and its shareholders have expended time and effort to keep the permits current and to optimize the project design. We do not intend to quit the field now that success is within sight.

## The Alaska Permits – Federal

A substantial amount of work has been completed by the Alaska Highway Project sponsors to date. Before discussing the specific permits held by Alaska Northwest it is important to better understand the unique regulatory and legislative framework under which these permits were issued, namely ANGTA.

ANGTA and the President's Decision remain in effect and can be terminated only by another act of Congress. ANGTA does not create a perpetual priority for the Alaska Highway Project. Rather, it establishes a priority designed to ensure that the Alaska Highway Project will be completed and begin initial operation in accordance with the decision of the President and

Congress. Once the Alaska Highway Project is in operation additional projects may be considered under the Natural Gas Act.

In implementing this priority, ANGTA requires that Federal agencies and officers expedite and issue "at the earliest practicable date" all permits and authorizations required by the Alaska Highway Project. In addition, ANGTA provides that applications and requests with respect to permits and authorizations required by the approved system "shall take precedence" over any similar applications and requests. Furthermore, ANGTA limits the discretion of Federal agencies and officers to include in certificates and permits for the Alaska Highway Project any conditions that would obstruct the system's expeditious construction and initial operation.

As required by ANGTA, the FERC in 1977 expeditiously issued a conditional certificate of public convenience and necessity for the Alaska Highway Project. That certificate contains no expiration date and is still in effect today.

In addition, Alaska Northwest holds a federal right-of-way grant issued in 1980 by the Department of Interior's Bureau of Land Management. That grant does not expire until December 2010, and may be renewed at the request of Alaska Northwest.

Furthermore, Alaska Northwest holds two recently extended Clean Water Act wetlands permits issued by the Army Corps of Engineers in coordination with many other agencies. Those permits were extended through September of 2007.

While these various federal permits were issued some time ago, they all are valid today. Indeed, nothing in ANGTA or in the certificates and authorizations issued for the Alaska Highway Project thereunder provides for the expiration of the chosen system's priority because completion of the Alaska segment was postponed until the U.S. domestic market could support it. Rather, the Alaska portion of the Alaska Highway Project has been held in reserve until the need for additional natural gas arises in the Lower 48 states is such that this section can be completed. As sponsors we have actively protected the preserved Alaska segment by maintaining all necessary certificates and permits and actively overseeing the rights-of-way.

We recognize that these certificates and permits need to be "updated" to capture changes in technology, markets and environmental requirements. We will do such updating, and it can be done within the ANGTA framework. To that end, a couple of additional points need to be emphasized before I move on to the State permits.

- First, ANGTA clearly envisions and provides for the ability to condition and to amend these permits. These powers are subject only to the limitation prohibiting changes in the "basic nature and general route" and actions that will "otherwise" prevent or impair in any significant respect the expeditious construction and initial operation of the Alaska Highway Project.

- Second, the Alaska Highway Project sponsors' requests for both new permits and amendments to existing permits must be given priority under ANGTA. This priority translates into a timing advantage for the Alaska Highway Project.

- Third, the authority of the Office of Federal Inspector, as transferred to the Secretary of Energy, also continues in effect today to expedite and coordinate federal permitting, enforcement of permit conditions, and facilitation and oversight of the construction and initial operation of the U.S. portion of the Alaska Highway Project.

- Fourth, ANGTA also provides for expedited and limited judicial review of actions taken by Federal agencies and officers.

- Finally, the Alaska Northwest Partnership is well along in permitting the Alaska Highway Project.

## The Alaska Permits – State of Alaska

On the state side, Alaska Northwest has a pending State of Alaska right-of-way lease application. Recently, we have initiated discussions with the State officials regarding perfecting and processing the pending application. Also at the state level, Alaska Northwest holds certificates of reasonable assurances issued pursuant to Section 401 of the Clean Water Act and a determination of consistency with the Coastal Zone Management Act.

## Additional Alaska Permits

While Foothills already holds the major permits necessary to construct the remainder of the Alaska Highway Project, there are additional permits and authorizations that will need to be obtained. For example, the Alaska Highway Project sponsors will need to acquire a permit under the Clean Air Act. However, these additional permits will be procured as the Project proceeds, and such procurement will not cause a delay in the expeditious construction of the Alaska Highway Project.

## The Canadian Permits

On the Canadian side, Foothills holds two unique certificates or permits:

- Certificate of public convenience and necessity.
- Yukon right-of-way.

### Certificate of Public Convenience and Necessity

The certificate of public convenience and necessity ("certificate") is the Order issued following a successful hearing before the National Energy Board (NEB) of a pipeline application. The information that is required to be filed for hearing purposes is delineated in regulation and includes details about supply and markets, environmental impact assessment, engineering, construction and operations plans and details about connecting pipeline facilities.

The preparation of the required hearing information generally takes one to two years to complete and the length of the hearing will be proportional to the level of controversy surrounding the issues.

Foothills has completed this phase of the process. We have the "certificates" that entitle us to build a pipeline, subject only to terms and conditions set out in the Alaska Highway Project regime.

The "certificates" are statutory. They were issued by the Parliament of Canada when it enacted the Northern Pipeline Act and are in keeping with the principles and intent of the U.S./Canada Agreement.

We acknowledge that the "certificates" were legislated 20 years ago and that some have raised questions about their scope and validity. Others suggest that the certificates are dated and accordingly must be reissued. The "certificates" are valid. We are on solid legal ground in this regard.

Changes to the pipeline design to accommodate new technical issues and improvements have previously have been granted by the Northern Pipeline Agency both at the time of the construction of the original Pre-build facilities and later during the facility expansion.

However, fundamental changes to the Canadian "certificates" would require changes to both the legislation and the treaty. For example another project could not be approved under the Alaska Highway Project regime. Further the Northern Pipeline Act (incorporating the U.S. /Canada Agreement) provides that the route for Alaska natural gas will be along the route set forth in Annex 1 to the U.S. /Canada Agreement i.e. the Alaska Highway route. In the face of the provision of the Northern Pipeline Act and the U.S. /Canada Agreement, a treaty with the force of law, it is difficult to see how the National Energy Board could entertain applications either for alternative pipeline routes for delivery of Alaska gas through Canada or applications by companies other than Foothills following the Foothills highway route for delivery of Alaska gas through Canada.

Given the above we may well ask what remains to be done before the project can proceed?

First of all, we do not have a commercial arrangement negotiated with the Alaska North Slope producers or other shippers. Achieving this commercial arrangement is our number one priority. We are confident that the mutual interests of all sides will ultimately lead to satisfactory arrangements.

Following the successful completion of such a commercial agreement, there are a number of terms and conditions that must be satisfied. These are set out in the Northern Pipeline Socio-economic and Environmental Terms and Conditions. It is our view that the terms and conditions are broad enough to accommodate modern environmental, engineering and construction practices. In fact, we addressed this issue when we pre-built the southern portion of the Alaska Highway Project pipeline.

Detailed design and engineering work also must be completed and approvals must be obtained from the Northern Pipeline Agency. It is this mechanism that I referred to when I indicated that we had a "fast track" regulatory process.

**The Yukon Right-of-Way**

I will take a few minutes to describe the status of our right-of-way through the Yukon. Foothills has been granted an easement in the Yukon. The current term of the easement is September 2012 and provisions are in place to renew the easement for a further term of 24 years. It is important to note that the easement is protected under the Encumbering Rights provisions of the Umbrella Final agreement which has been signed by the Government of Canada, the Government of the Yukon and the Yukon First Nations. The Final Settlement Agreements that have been negotiated with the Yukon First Nations contain specific provisions relating to the easement. In addition, the compressor stations locations and permanent access to the proposed stations are protected.

What does this mean? From our perspective this translates into certainty of land tenure and a significant timing advantage. Foothills has developed an excellent working relationship with the Yukon First Nations over the years and we are building on that relationship. Like the Canadian "certificates" the easements also constitutes an important asset. An asset not easily replicated.

**Conclusion**

Let me summarize and focus on some of the key points.

Foothills is a company with real pipelines and real customers.

When combined with our shareholders TransCanada and Westcoast, we transport 20% of all the natural gas consumed in the United States. And we have the know-how and the where-with-all to build the Alaska Highway Pipeline.

We have been involved in this project for 25 years.

We and our former partners have invested heavily to achieve the permits, certificates, rights-of-way and much of the engineering on the Alaska Highway pipeline.

A basic message that I want to leave with you is this, we have a...very unique and solid regulatory framework, it is a very valuable framework in terms of saving money and avoiding costly delays when building a pipeline. It is more than a collection of permits. It is a package, designed specifically to expedite building the Alaska Highway pipeline.

This framework can neither be duplicated nor terminated easily. It is a one-of-a-kind regime. I urge all Alaskans to take full advantage of it.

Finally let me raise one other issue and that is the matter of the pipeline route decision. Before we can move from discussion to action this must be resolved. Anything this committee can do to bring clarity to the routing debate will be a positive development.

Ultimately all stakeholders must find some common ground and go forward.

So where do we go from here?

A commercial agreement between pipelines and producers is the next major mile post for the Project.

Once a satisfactory commercial arrangement is achieved ... the flag drops; from that point on we believe that our regulatory framework will allow "shovels to be in the ground" within 24 months.

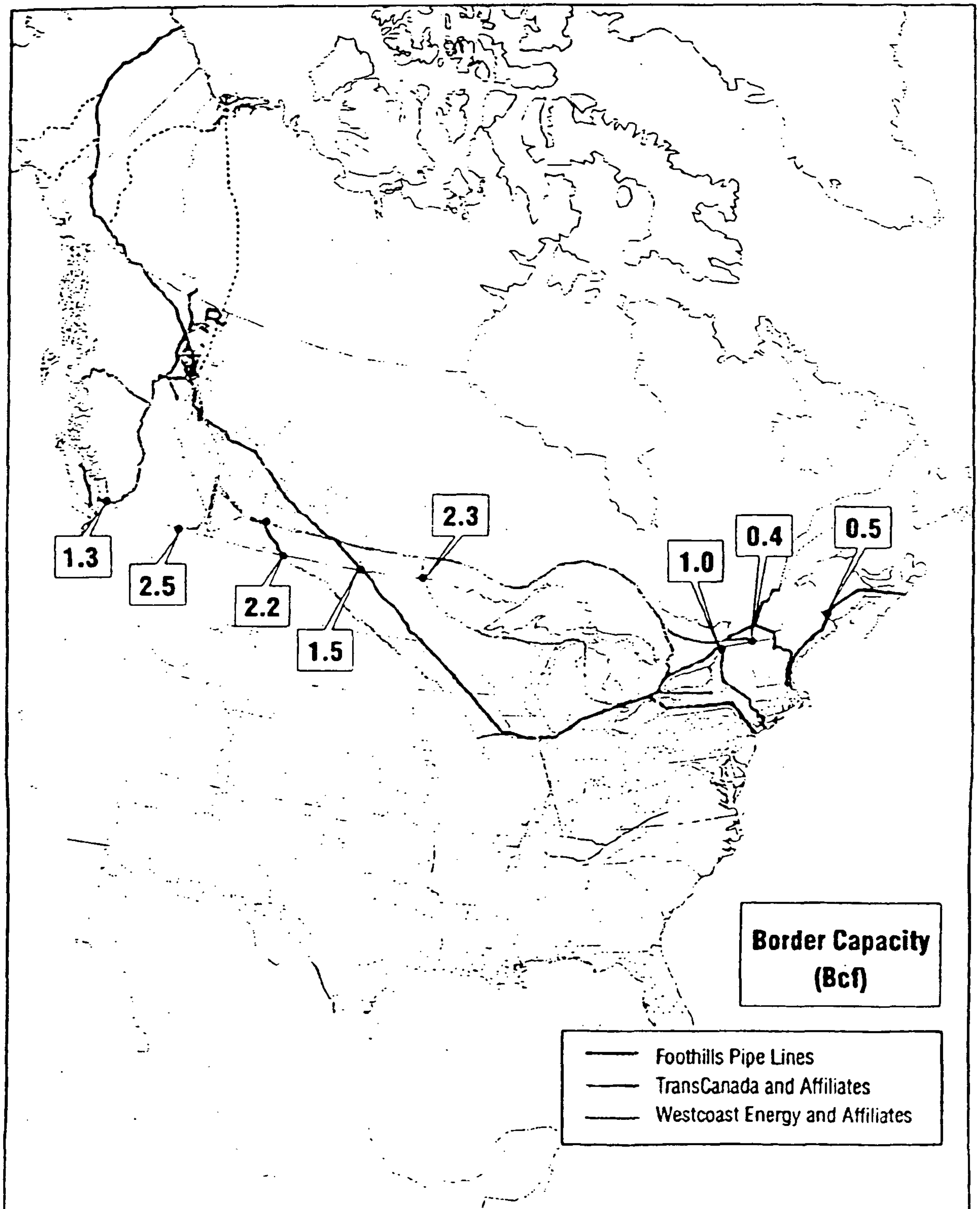
This is a very large project. It will involve many companies. It will cost a lot of money and there will be lots of issues to address and benefits to share.

Foothills and its shareholders intend to be major players in the development and operation of this important pipeline and we believe that we bring value to the Project and value to Alaska.

Thank you, and I am now prepared for questions.

FOOTHILLS PIPE LINES LTD.

# NORTH AMERICAN PIPELINE INFRASTRUCTURE

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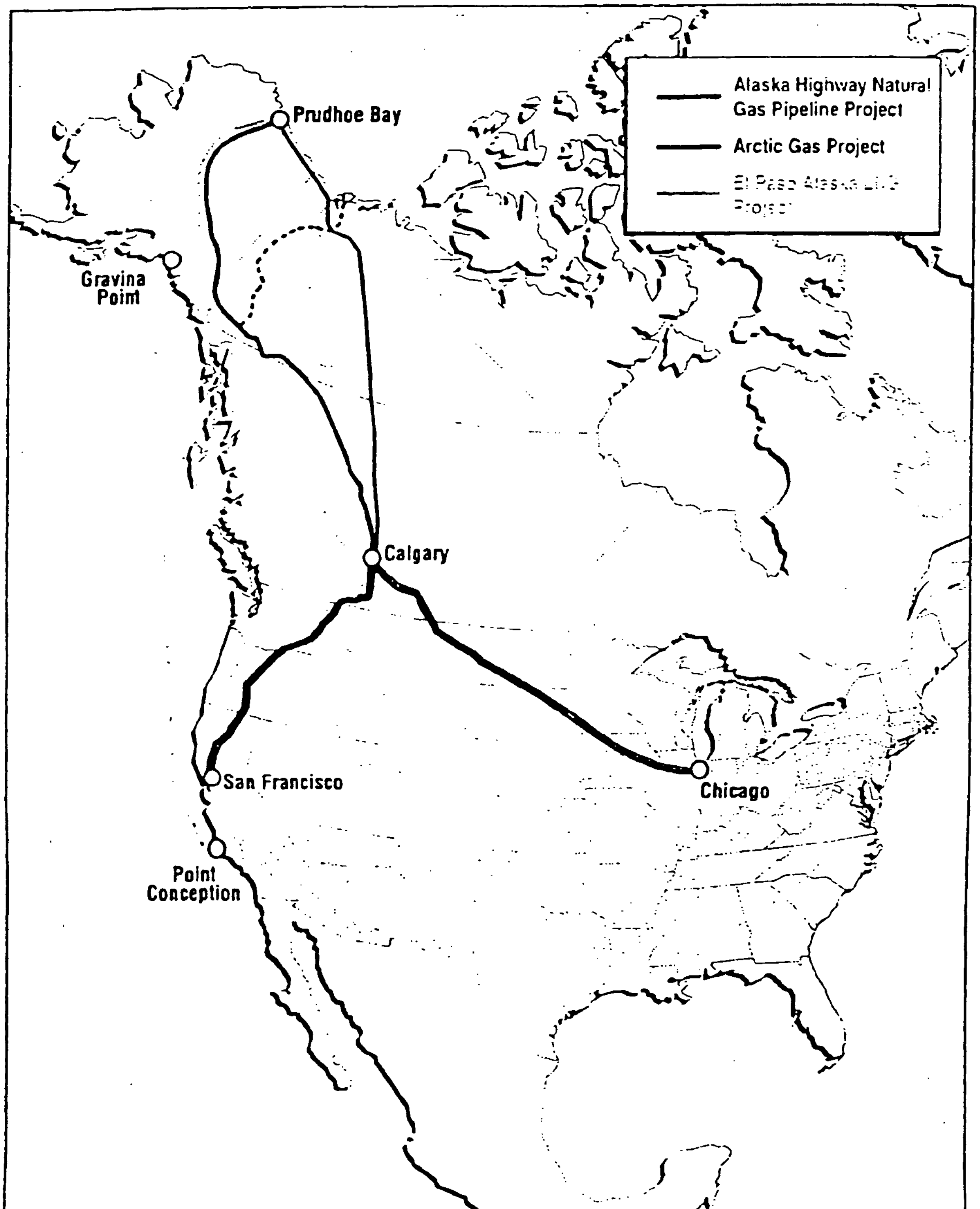
# ORIGINAL COMPETING PROJECTS



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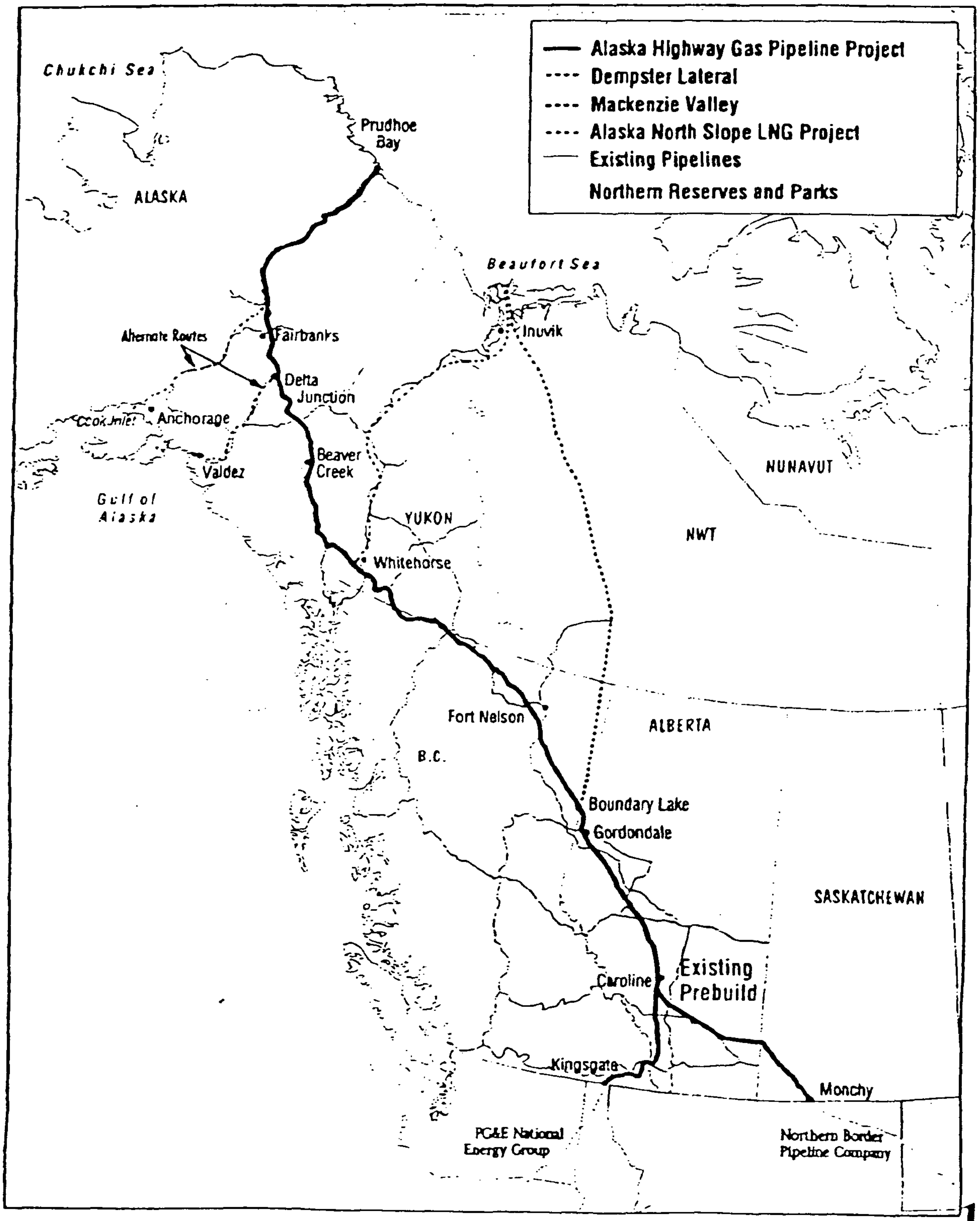
# TRANSPORTATION SYSTEMS

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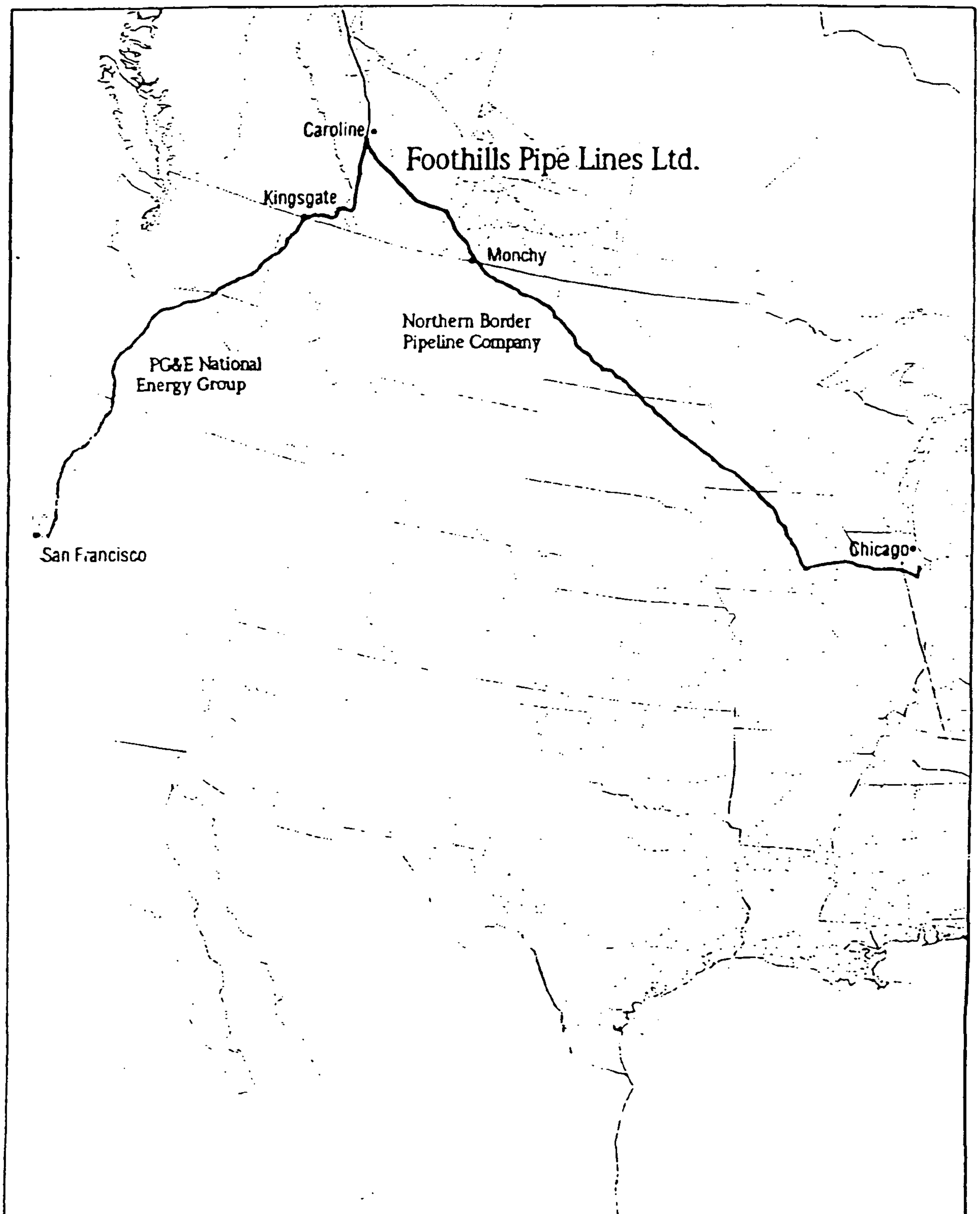
# PREBUILD SYSTEM

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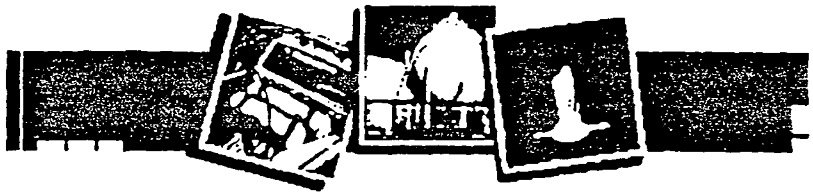
Energy Efficiency and Renewable Energy Network (EREN) U.S. Department of Energy

Hydrogen



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## Hydrogen Energy Topics

Hydrogen is the third most abundant element on the earth's surface, where it is found primarily in water ($H_2O$) and organic compounds. It is generally produced from hydrocarbons or water; and when burned as a fuel, or converted to electricity, it joins with oxygen to again form water.

More basic information about hydrogen energy is also available.

### Technologies

**Production**

Hydrogen is produced from sources such as natural gas, coal, gasoline, methanol, or biomass through the application of heat; from bacteria or algae through photosynthesis; or by using electricity or sunlight to split water into hydrogen and oxygen.

**Transport and Storage**

The use of hydrogen as a fuel and energy carrier will require an infrastructure for safe and cost-effective hydrogen transport and storage.

**Fuel Cells**

Hydrogen's potential use in fuel and energy applications includes powering vehicles, running turbines or fuel cells to produce electricity, and generating heat and electricity for buildings. The current focus is on hydrogen's use in fuel cells.

### Issues

**Safety**

Hydrogen has an excellent safety record, and is as safe for transport, storage and use as many other fuels. Nevertheless, safety remains a top priority in all aspects of hydrogen energy. The hydrogen community addresses safety through stringent design and testing of storage and transport concepts, and by developing codes and standards for all types of hydrogen-related equipment.

**The Hydrogen Economy**

The vision of building an energy infrastructure that uses hydrogen as an energy carrier — a concept called the "hydrogen economy" — is considered the most likely path toward a full commercial application of hydrogen energy technologies.

**Hydrogen Organizations & Resources**

- U.S. Department of Energy
- U.S. Federal Government
- U.S. State and Local
- U.S. Trade and Nonprofit
- U.S. Universities and Research Institutes
- International Organizations
- Discussion Groups
- Newsletters and Magazines
- Products and Services

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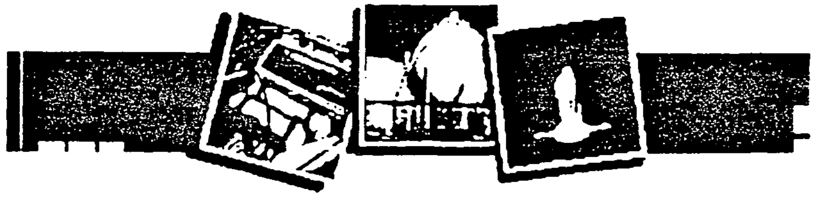
Hydrogen







## Hydrogen Energy Basics

Hydrogen is the simplest element; an atom consists of only one proton and one electron. It is also the most plentiful element in the universe. Despite its simplicity and abundance, hydrogen doesn't occur naturally as a gas on the Earth—it is always combined with other elements. Water, for example, is a combination of hydrogen and oxygen ($H_2O$). Hydrogen is also found in many organic compounds, notably the "hydrocarbons" that make up many of our fuels, such as gasoline, natural gas, methanol, and propane.

Hydrogen can be made by separating it from hydrocarbons by applying heat, a process known as "reforming" hydrogen. Currently, most hydrogen is made this way from natural gas. An electrical current can also be used to separate water into its components of oxygen and hydrogen. Some algae and bacteria, using sunlight as their energy source, even give off hydrogen under certain conditions.

Hydrogen is high in energy, yet an engine that burns pure hydrogen produces almost no pollution. NASA has used liquid hydrogen since the 1970s to propel the space shuttle and other rockets into orbit. Hydrogen *fuel cells* power the shuttle's electrical systems, producing a clean byproduct—pure water, which the crew drinks. You can think of a fuel cell as a battery that is constantly replenished by adding fuel to it—it never loses its charge.

Fuel cells are a promising technology for use as a source of heat and electricity for buildings, and as an electrical power source for electric vehicles. Although these applications would ideally run off pure hydrogen, in the near term they are likely to be fueled with natural gas, methanol, or even gasoline. Reforming these fuels to create hydrogen will allow the use of much of our current energy infrastructure—gas stations, natural gas pipelines, etc.—while fuel cells are phased in.

In the future, hydrogen could also join electricity as an important *energy carrier*. An energy carrier stores, moves, and delivers energy in a usable form to consumers. Renewable energy sources, like the sun, can't produce energy all the time. The sun doesn't always shine. But hydrogen can store this energy until it is needed and can be transported to where it is needed.

Some experts think that hydrogen will form the basic energy infrastructure that will power future societies, replacing today's natural gas, oil, coal, and electricity infrastructures. They see a new *hydrogen* economy to replace our current energy economies, although that vision

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| Table 10. Estimated Consumption of Vehicle Fuels in the United States, 1992-2001 (Thousand Gasoline-Eq | | | | | | | |
|---|---|---|---|---|---|---|---|
| Fuel | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 |
| **Alternative Fuels** | | | | | | | |
| Liquefied Petroleum Gases (LPG) | 208,142 | 264,655 | 248,467 | 232,701 | 239,158 | 238,356 | 241,583 |
| Compressed Natural Gas (CNG) [a] | 16,823 | 21,603 | 24,160 | 35,162 | 46,923 | 65,192 | 73,251 |
| Liquefied Natural Gas (LNG) | 585 | 1,901 | 2,345 | 2,759 | 3,247 | 3,714 | 5,343 |
| Methanol, 85 Percent (M85) [b] | 1,069 | 1,593 | 2,340 | 2,023 | 1,775 | 1,554 | 1,212 |
| Methanol, Neat (M100) | 2,547 | 3,166 | 3,190 | 2,150 | 347 | 347 | 449 |
| Ethanol, 85 Percent (E85) [b] | 21 | 48 | 80 | 190 | 694 | 1,280 | 1,727 |
| Ethanol, 95 Percent (E95) [b] | 85 | 80 | 140 | 995 | 2,699 | 1,136 | 59 |
| Electricity | 359 | 288 | 430 | 663 | 773 | 1,010 | 1,202 |
| **Subtotal** [a] | **229,631** | **293,334** | **281,152** | **276,643** | **295,616** | **312,589** | **324,826** |
| **Oxygenates** | | | | | | | |
| Methyl Tertiary Butyl Ether (MTBE) [a c] | 1,175,000 | 2,069,200 | 2,018,800 | 2,691,200 | 2,749,700 | 3,104,200 | 2,903,400 |
| Ethanol in Gasohol [a] | 701,000 | 760,000 | 845,900 | 910,700 | 660,200 | 830,700 | 889,500 |
| **Total Alternative and Replacement Fuels** [d] | **2,105,631** | **3,122,534** | **3,145,852** | **3,878,543** | **3,705,516** | **4,247,489** | **4,117,726** |
| **Traditional Fuels** | | | | | | | |
| Gasoline [a e] | 110,135,000 | 111,323,000 | 113,144,000 | 115,943,000 | 117,783,000 | 119,336,000 | 122,849,000 |
| Diesel | 23,866,000 | 24,296,630 | 27,293,370 | 28,555,040 | 30,101,430 | 31,949,270 | 33,665,360 |
| **Total Fuel Consumption** [a f] | **134,230,631** | **135,912,964** | **140,718,522** | **144,774,683** | **148,180,046** | **151,597,859** | **156,839,186** |

[a] 1999 estimate has been revised.
[b] The remaining portion of 85-percent methanol and both ethanol fuels is gasoline. Consumption data include t
[c] Includes a very small amount of other ethers, primarily Tertiary Amyl Methyl Ether (TAME) and Ethyl Tertiary
[d] Does not include biodiesel for which data are not currently available.
[e] Gasoline consumption includes ethanol in gasohol and MTBE.
[f] Total fuel consumption is the sum of alternative fuel, gasoline, and diesel consumption. Oxygenate consumptic
Notes: Fuel quantities are expressed in a common base unit of gasoline-equivalent gallons to allow comparisor

equivalent gallons do not represent gasoline displacement. Gasoline equivalent is computed by dividing the lowe the lower heating value of gasoline and multiplying this result by the alternative fuel consumption value. Lower he unit of fuel excluding the heat produced by condensation of water vapor in the fuel. Totals may not equal sum of

Estimates for 1999 are revised. Estimates for 2001, in italics, are based on plans or projections. Estimates for t reports if new information becomes available.

Sources: 1992-2001 Oxygenate Consumption: Energy Information Administration, Petroleum Supply Monthly. Energy Information Administration, Petroleum Supply Annual, Volume 1 (June 2000). Highway use of gasoline w consumption, based on data in the Transportation Energy Data Book: Edition 16, prepared by Oak Ridge Nation Energy (July 1996). Diesel consumption was adjusted for highway use by multiplying by .568 derived from Energ Kerosene Sales 1999. 2000-2001 Oxygenate and Traditional Fuel Consumption: Energy Information Administrati September 2000. Alternative Fuel Consumption: Energy Information Administration, Office of Coal, Nuclear, Elec 1995, Science Applications International Corporation, "Alternative Transportation Fuels and Vehicles Data Devel prepared for the Energy Information Administration (McLean, VA, July 1996).


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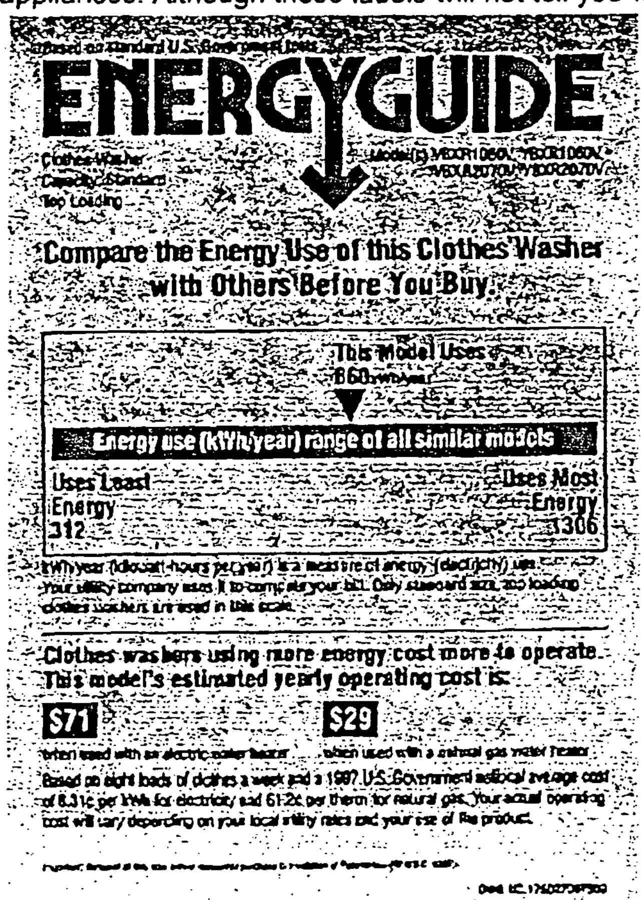
Home

# EnergyGuide Labels

The U.S. government established a mandatory compliance program in the 1970s requiring that certain types of new appliances bear a label to help consumers compare the energy efficiency among similar products. In 1980, the Federal Trade Commission's Appliance Labeling Rule became effective, and requires that EnergyGuide labels be placed on all new refrigerators, freezers, water heaters, dishwashers, clothes washers, room air conditioners, heat pumps, furnaces, and boilers. These labels are bright yellow with black lettering identifying energy consumption characteristics of household appliances. Although these labels will not tell you which appliance is the most efficient, they will tell you the annual energy consumption and operating cost for each appliance so you can compare them yourself.




EnergyGuide labels show the estimated yearly electricity consumption to operate the product along with a scale for comparison among similar products. The comparison scale shows the least and most energy used by comparable models. The labeled model is represented by an arrow pointing to its relative position on that scale. This allows consumers to compare the labeled model with other similar models. The consumption figure printed on EnergyGuide labels, in kilowatt-hours (kWh), is based on average usage assumptions and your actual energy consumption may vary depending on the appliance usage.

EnergyGuide labels are not required on kitchen ranges, microwave ovens, clothes dryers, on-demand water heaters, portable space heaters, and lights.

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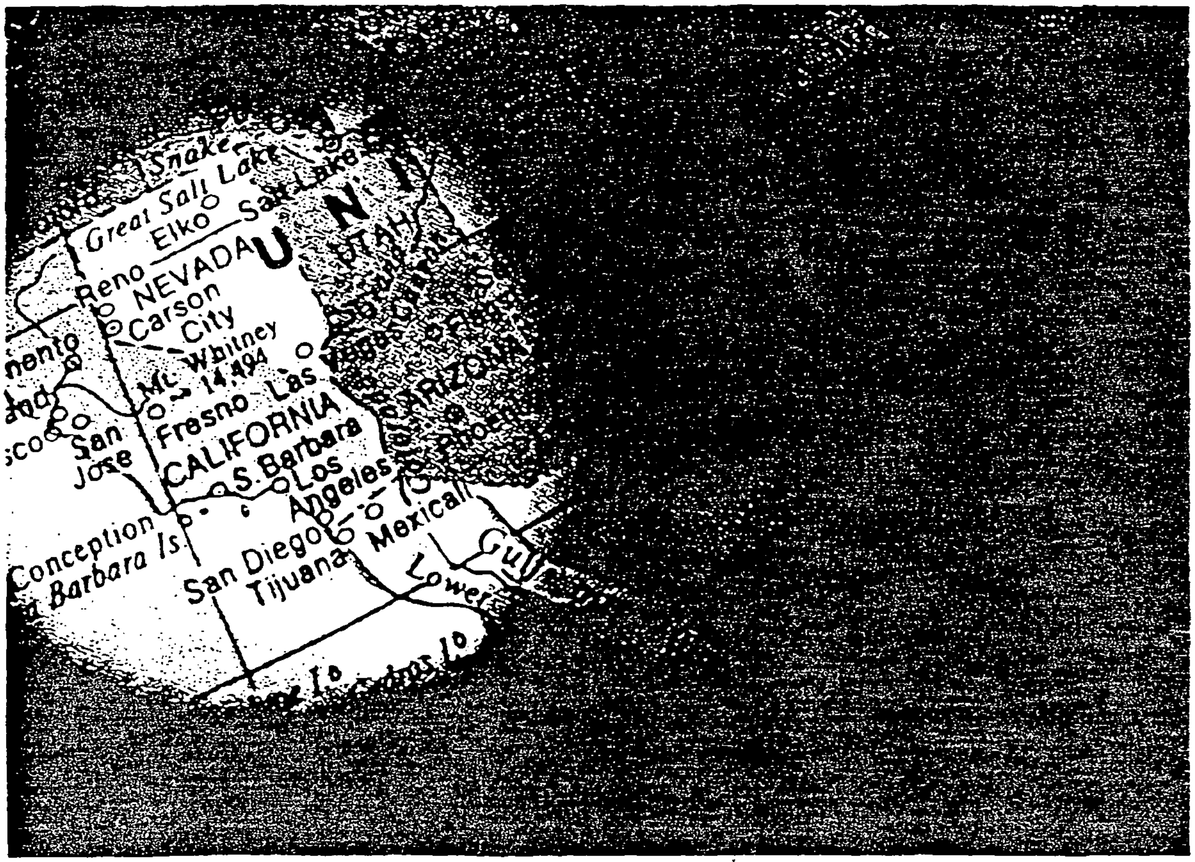
# POWER STRUGGLE.




As California struggles with blackouts, other western states strive to meet growing electricity demands. It's time for America to encourage the construction of new electric generation utilizing all of America's diverse energy resources including power plants that generate electricity from coal. And with coal reserves that will last for 250 years, electricity from coal will be a reliable and affordable energy resource long into the future.

Surprisingly, electricity generated from coal is cleaner than ever. America's electric companies that use coal have invested tens of billions of dollars in new technologies to generate electricity from coal more cleanly and efficiently. Since 1970, coal use in our nation's power plants has nearly tripled while emissions of major air pollutants have dropped by a third. And newer technologies promise even better results in the future.

We are CARE—a coalition dedicated to the development of a sound energy policy for America. To find out more, click on www.CAREenergy.com.

**ESSENTIAL, AFFORDABLE, AND INCREASINGLY CLEAN: ELECTRICITY FROM COAL.**

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# ENERGY POLICY
# PRINCIPLES FOR ACTION
# NATIONAL MINING ASSOCIATION

Reliable affordable energy is necessary for both economic growth and national security. All domestic energy resources – coal, natural gas, petroleum, nuclear (uranium) and renewables – will be required and each is essential to meeting the nation's future energy needs. Use of domestic energy resources must increase while we simultaneously develop, produce and use energy more efficiently and cost effectively while we maintain and improve the quality of our environment.

Energy policy must be based on several underlying principles: economic efficiency and support for market based policies; advancing energy technology; use of additional regulations only if based on sound science and relative risk assessments; and, expanded use of incentives to promote investment in technology and infrastructure. Policy must be able to recognize and react to the rapidly changing energy requirements of our society and to advances in technology. As recent events clearly illustrate, energy policy must address both energy supply and energy demand.

**Energy Policy and Coal.**

The need for a dynamic energy policy is underscored by rapid electrification of our economy. Affordable and reliable electricity has supported much of the economic expansion of the past several years and affordable and reliable electricity is necessary to support the economy of the future.

Coal is electricity. Over one-half of the nation's electricity requirements are met with coal-fired power. Coal is the nation's largest and most affordable domestic resource. Coal must be a major factor in the future as demand for electricity continues to increase at a rapid pace.

**Coal generating capacity and coal use must increase to support a growing demand for electricity; efficiency and environmental performance must continue to improve.**

The nation's electric generating fleet is not sufficient to meet current, let alone future, demands for electricity. Barriers to construction of generation and transmission infrastructure must be removed, regulatory certainty with respect to criteria pollutants is necessary and incentives to increase environmental performance and power generation efficiency are necessary to spur investment to ensure that additional capacity is built and existing capacity upgraded. Fuel diversity, and affordability are essential for economic growth. Coal must be used in existing plants and much of the new capacity must be advanced clean coal technology.

- The Administration should support legislative and regulatory actions that provide a measure of burden sharing to improve operational and environmental performance of the existing coal-based fleet and incentivize construction of a number of commercial applications of advanced clean coal technologies.
- Future regulation of criteria and hazardous air pollutants from coal-based electricity generation, if warranted by sound economic and scientific considerations, should be implemented under a well defined and integrated strategy to optimize control and minimize costs. The Administration should take immediate steps to harmonize air quality regulations currently pending at EPA.
- Climate policy is an integral part of energy policy. Command and control regimes to control or reduce greenhouse gas emissions should not be part of the policy. Policies should encourage aggressive voluntary actions to reduce emissions, development of new technologies and accelerated research in sequestration. The United States' climate policy must recognize the global nature of the issue and support responsible international agreements that focus on technology transfer and on energy efficient economic development throughout the world.

### Investments in Coal Production Capacity Must Be Facilitated

Coal output is approaching 1.1 billion tons annually. Production is forecast to increase by 250 million over the next decade to meet demand. Unnecessary barriers to coal reserves must be removed and income tax policies should encourage, not discourage, investments in expanding capacity, while continuing to incentivize the highest safety and environmental standards in the world.

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**OVERVIEW**

COAL AND URANIUM
THE FOUNDATION FOR THE US ENERGY/ELECTRIC ECONOMY

ENERGY DRIVES THE US ECONOMY. Energy, whether it is from coal, oil, natural gas, uranium or renewable sources, is the common denominator that is imperative to sustain economic growth, enhance environmental protection, maintain and improve standards of living and, simultaneously, support an expanding population. The significant economic expansion that has occurred in the United States over the past two decades, and especially over the last five years, was in no small measure due to reliable and affordable energy, much in the form of electricity, much in the form of coal-fired electricity.

According to the Energy Information Administration[1], the trends experienced in the US over the last 20 years - economic growth, greater efficiency and a move to electricity - are expected to continue over the next two decades. Economic growth is forecast to increase by an average 2.3 percent per year. Reflecting greater efficiency, the use of energy will grow by an average 1.3 percent per year or by a total of 32 percent to 127 quadrillion Btu by 2020. Consumption of all sources of energy are expected to increase: petroleum by 33 percent, natural gas by 62 percent, coal by 22 percent and renewable energy by 26 percent. The economy will become even more dependent upon electricity over the next 20 years. During the next two decades consumption of electricity will increase by an average 1.8 percent per year or by over 40 percent.

THE GAP BETWEEN ENERGY SUPPLY AND DEMAND. Many policies will have to change to make this forecast a reality. There is a growing gap between the expected demand for energy and the nation's capacity to supply that energy on a reliable, affordable basis. Since 1980 consumption of energy has increased by 20 quadrillion Btu (Quads) or by 25 percent to 98.5 Quads. Production of energy in the United States has not kept pace, increasing by a mere 5 quadrillion Btu or by only 7.6 percent, to 72.6 quads. The "gap" in 2000, 26 quadrillion Btu, was made up by importing energy.

Over the next twenty years the gap will widen. Energy consumption is expected to increase by 29 quads but US energy production will increase by only 14 quads widening the "gap" to 41 quadrillion Btu. This gap can only be filled through an increase in energy imports.

The energy policies of the past eight years have exacerbated the US demand –supply imbalance. Domestic policies have actively discouraged, and even prevented, investments in domestic energy production capacity, in our electrical grid, in our nation's energy delivery infrastructure. As pointed out, the increase in energy use in the United States during this time was fueled in large part by an increase in imports - a trend expected to continue. The increase in the generation of electricity was possible because generating capacity had been over built in the 70's and 80's giving the US substantial reserve margins. Those reserves are gone. The benefits of past investment have run out. The energy supply industry has not been able to make the investments or develop and maintain the infrastructure that is necessary for the future.

[1] Annual Energy Outlook 2001, Energy Information Administration, December 2000.

The US is fortunate to have a large domestic energy resource within our borders and an established, although aging, energy delivery structure. To meet expected future demands our national energy policy must be redirected to encourage efficient, environmentally sound development of our nation's vast energy resource base and to promote the use of technologically advanced methods to process, transport and use that energy.

COAL IN THE ENERGY MIX. Coal reserves, which are geographically distributed throughout the US, comprise the greatest share of the nation's energy resource base. The demonstrated coal reserve is over 500 billion tons with economically recoverable reserves of over 275 billion tons. This is a reserve large enough to support a growing coal demand for over well over 200 years.

Coal is the only domestic energy resource to INCREASE production levels over the last two decades. In 1980, coal production was 830 million short tons. In 2000, 1.1 billion tons of coal were produced in mines located in 26 states and the EIA projects coal production of 1.3 billion tons in 2020. During the past two decades average productivity in the coal industry has increased by nearly 250 percent reflecting in part shifts from underground to surface production and, in part, technological advances in mining operations. The average price of a ton of coal at the mine has declined in both real and nominal terms. The US coal industry is proud to pay wages to our miners that are among the highest of any industrial worker in the country. The US industry is the safest coal industry in the world, a record of which we are all proud, but a record on which we will not rest as the goal of the industry is zero injuries and fatalities.

Coal, or electricity generated from coal is used in all 50 states. The coal industry contributes some $161 billion annually to the economy through payroll and purchases of goods and services. Coal industry tax payments add at least $2 billion annually to state and local government revenues. The industry directly and indirectly employs nearly 1 million people.

The primary market for coal is the electric generator. Last year 1.026 billion tons of coal were used to generate over 50 percent of all electricity used in the US. The industrial market, at approximately 32 million tons per year, and the domestic market for coking coal of 28 – 29 million tons are both very important, but small in comparison. The United States also exports coal, approximately 57 million tons in 2000. Coal use in the industrial and coking markets and for export will remain relatively unchanged over the next 20 years.

At the bottom line, coal is electricity.

The Energy Information Administration forecast referenced above shows that by 2020 electricity use will increase by over 40 percent as compared to today's levels. Coal use for electricity will total at least 1.25 billion tons in 2020 some 250 million tons,or 20 percent, more than is currently burned.

The reasons are straightforward: coal is domestic, coal is reliable and coal is affordable. To illustrate, in 2000 electric rates in regions dependent upon coal for electricity were, on average, at least one-third lower than rates in regions dependent upon other fuels for electricity.[2]

And, coal is increasingly clean. Although coal use for electricity has tripled since 1970, emissions are lower by more than a third. New advanced clean coal technologies will enable this trend to continue and to accelerate, permitting greater use of coal while increasing combustion efficiencies and lowering emissions of the regulated criteria pollutants (SO2, NOx, and Particulate Matter). Emissions of carbon dioxide both overall and per unit of electricity generated will be lower as well.

Coal serves an indispensable role in the United States energy equation and not only can, but will, provide a major part of the nation's energy requirements in the future.

**US URANIUM IS ALSO AN IMPORTANT PART OF THE US ENERGY/ELECTRIC ECONOMY.** The United States uranium recovery industry is also important to the nation's energy independence and is essential to national security. Today, nearly 23 percent of America's electricity comes from clean nuclear power, which translates into the consumption of about 45 million pounds of uranium each year. However, the collapse in uranium prices since 1980 has produced a sharp decline in the viability of America's uranium mining industry. America's remaining uranium miners produce only about 3 million pounds of uranium annually, just 6 percent of nuclear utilities' needs. The balance of the uranium comes from rapidly declining inventories in the hands of the utilities, the federal government and foreign entities.

Under the current policy direction, the amount of electricity generated by nuclear plants is expected to decline over the next twenty years. However, this forecast may prove to be incorrect. Licenses for nuclear plants are being renewed and it is expected that almost all nuclear plants operating in the US today will apply for, and obtain, renewals to allow operation for 20 years beyond the original date at which licenses were due to expire. There is some consideration of construction of at least one new nuclear plant. Thus, demand for uranium for will not decline but is likely to increase.

Historically, the United States was the world's leading producer of uranium and still has extensive proven reserves of natural uranium that offer the potential for secure sources of future supply. Only a strong domestic uranium recovery industry can assure an adequate long-term supply of uranium for the nuclear power component of the nation's long-term energy policy and preclude threats of foreign supply disruptions or price controls that could adversely affect the nation's common defense and security. Therefore, the federal government must foster energy policies that ensure a strong and viable domestic uranium recovery industry and must remove barriers to domestic production of existing sources of uranium.

**DEVELOPMENT OF AN ENERGY STRATEGY MUST BE A PRIORITY IF FUTURE DEMANDS ARE TO BE MEET.** A change in policy direction is required if affordable energy is to be reliably available in the future. At the core, American's energy strategy must be grounded in market-based policies that lead to adequate, diverse and secure

[2] According to the Energy Information Administration electric rates in the New England and Middle Atlantic States averaged 9.9 cents per Kwh through October 2000, 9.0 cents in California. As comparison, electric rates in the East South Central region (dependent upon coal for over 70% of generation) averaged 5.2 cents per Kwh in the same time frame.

energy supplies. A balanced energy policy will be anchored in economic efficiency, will promote new energy technologies, will limit use of regulation and will support use of market based incentives. A responsible energy policy will achieve a balance between the benefits of energy use and the benefits of responsible environmental protection.

Polices are needed to:

- Enhance energy supply and encourage use of all energy sources;
- Provide certainty for investment in energy infrastructure (environmental controls, generation and transmission);
- Balance energy production and use with environmental concerns;
- Promote energy efficiency and conservation;
- Assure free and competitive energy markets that in turn work to provide energy at affordable costs; and,
- Promote energy technology development and long-range R&D initiatives.

A comprehensive energy policy should include tax and fiscal policies, trade policies environmental policies, and land use policies. Finally, an energy policy needs to be predictable and must make certain that the policies and activities of the various government agencies are coordinated and complementary rather than working towards goals that are conflicting.

Although many policies will be similar or even identical for all fuel sources, many will be fuel specific. The issues that follow are issues that must be resolved if coal is to continue to be a major part of the nation's energy mix.

## COAL USE

- New Coal Generation Capacity is Required to Meet Future Demands
  National Electricity and Environmental Technology Act
- Harmonizing Ozone Rules Under the Clean Air Act
- Regulation of Mercury Emissions from Coal- and Oil-Based Power Plants
- New Source Review
  Older Power Plants Not Exempt From Clean Air Act
- Regional Haze Regulations
- Rulemaking to Establish BART Guidelines
- Use of the CALPUFF Model for Impact Analysis
- The Importance of Fuel Diversity in Establishing a National Energy Policy and a Sound Climate Change Strategy

## NEW COAL GENERATION CAPACITY IS REQUIRED TO MEET FUTURE DEMANDS
## NATIONAL ELECTRICITY AND ENVIRONMENTAL TECHNOLOGY ACT

PRINCIPLE: Incentives to improve efficiency and environmental performance at existing power generating facilities and to encourage new plant construction using advanced clean coal technologies are necessary to ensure fuel diversity and an affordable, reliable electricity supply.

BACKGROUND: The economy of the 21st century will require reliable, clean and affordable electricity to keep the engine running, the lights on and the computers humming. The Department of Energy forecasts that by the year 2020, U.S. electricity consumption will be over 40% higher than today. A large number of new base load electric generating plants will be required to meet this new electricity demand at affordable prices.[1] Today, more than one-half of U.S. electricity is generated from abundant, low cost, domestic coal but new coal based generating plants are not being built. To illustrate, over 43,000 megawatts (MW) of coal capacity came on line between 1980 and the end of 1984. In the past five years, only 3,500 MW of new coal capacity have been brought on line. This is largely due to uncertainty about new environmental requirements and the risks associated with large investments as the utility industry becomes more competitive. The development and commercialization of more efficient and lower emitting clean coal technologies is necessary to continue the improvement in emissions from coal-based generation and to maintain the option for new coal-based generating plants. Coal-based electricity generation needs to be preserved and expanded to ensure a diversity of fuel supply, produce affordable and reliable electricity, maintain a strong economy, and help stabilize the balance of payments.

DESCRIPTION: In the short term the challenge is twofold: first, to expand the use of newer more advanced NOx and SO2 control technologies in existing plants through retrofits and secondly, to move new advanced clean coal technologies that have been proven at the demonstration stage to, and through, placement in the commercial marketplace. The National Electricity and Environmental Technology Act (NEET) was developed to meet this dual challenge. The proposed legislation has three important programs:

- A financial incentives program that designed to cushion the financial burden of applying advanced technologies to existing coal units;
- A demonstration program that provides tax incentives and/or financial assistance for initial commercial scale application of advanced coal based generating technologies contingent upon achievement of specificed requirements for efficiency gains; and,
- An R&D program that addresses long-term technology needs.

These programs would result in significant reductions of emissions. NOx emissions would be reduced by 631,000 tons, SO2 emissions by over 1.9 million tons and CO2

[1] The Energy Information Administration forecasts show that nearly 400 GW of new and replacement capacity will be required by 2020, the equivalent of 1,300 plants at 300 MW each. Some 378 MW of the needed capacity is still in the "unplanned" stage.

emissions by over 1.2 million tons. This is because advanced technologies are cleaner burning and are more efficient in the process of turning coal into electricity.

STATUS: The NEET bill has bi-partisan support. It was introduced by Senators Byrd and McConnell in January 2001 as S.60. The NEET provisions are included in Senator Murkowski's comprehensive energy bill, S, 388/389. Introduction in the House is expected soon as a bi-partisan bill.

RECOMMENDATION: The Administration should support legislation as described above that meets the President's commitment to Clean Coal Technology and that (1) enhances funding for coal-based R&D; (2) provides a measure of burden sharing to improve the efficiency and environmental performance of existing coal-based generating facilities; and (3) implements a set of financial incentives and risk sharing for a limited number of early commercial applications of advanced clean coal technology.

## HARMONIZING OZONE RULES UNDER THE CLEAN AIR ACT

PRINCIPLE: Provide certainty by administratively synchronizing the NOx reduction compliance deadlines of 2003 in the EPA Section 126 rule and the 2004 court ordered "SIP call" deadline.

DESCRIPTION: In January 2000, EPA issued its Clean Air Act "section 126" rule, requiring power plants and some industrial sources in 13 states to make significant cuts in nitrogen oxide ($NO_x$) emissions to help four states (Connecticut, Massachusetts, New York and Pennsylvania, all of which filed petitions under section 126 requesting source-specific reductions) reduce their ozone levels. EPA insists targeted sources must comply by May 1, 2003, even though this date would make compliance very difficult because of the lead time needed to engineer, purchase, install and test emission control equipment. More importantly, this deadline conflicts with a court-ordered May 31, 2004 compliance date for EPA's "SIP call" rule. The SIP call requires $NO_x$ reductions from power plants and some other sources in 22 eastern states, including those subject to the section 126 rule, and will necessitate capital costs in excess of $13 billion and associated O&M costs of at least this much. The North American Electric Reliability Council has issued a study concluding that pending $NO_x$ reductions will require many Midwestern coal-fired plants to retrofit with sophisticated new technologies, thus significantly increasing planned maintenance outages (on top of projected low reserves), and hence some reliability risks in the next several years. $NO_x$ controls are imminent, but it is imperative that reductions occur in the least burdensome and most economically responsible manner possible.

The section 126 rule also removes state flexibility to decide which sources to control and by how much. Many states want the section 126 rule deadline to be the same as the SIP call compliance date, or made inapplicable for states that implement the SIP call. Some northeast states, companies and environmental groups want the section 126 rule and its deadline retained. Congressional appropriators have repeatedly urged EPA to harmonize the section 126 rule and SIP call implementation dates.

STATUS: The Supreme Court denied an appeal by parties challenging the underlying merits of the SIP call rule; however, this did not affect the May 31, 2004 compliance date. Legal challenges to the section 126 rule are pending in the D.C. Circuit Court of Appeals. A decision is expected by spring 2001, but may not resolve the SIP call/section 126 conflict. In the interim, states face significant uncertainty in developing implementation plans. Similarly, regulatory certainty is *critical* to companies, yet affected sources currently do not know which deadline and what controls apply.

DECISION: The Section 126 and SIP call rules must be harmonized.

RECOMMENDATION: Congress clearly intended that the SIP call process would drive state compliance with Clean Air Act emission reduction requirements. The section 126 rule explicitly provides the Administrator authority to deny, or withdraw prior approval of, any section 126 petition targeting sources in a state where EPA approves that particular state's implementation plan. The Administrator should clarify immediately that the SIP call implementation schedule is controlling and that $NO_x$ reductions must be made by the May 31, 2004 compliance date.

## REGULATION OF MERCURY EMISSIONS FROM COAL- AND OIL-BASED POWER PLANTS

PRINCIPLE: Review the EPA mercury regulatory determination to ensure it is based on sound science, provides flexibility for use of market based programs in compliance; ensures technological feasibility of any controls required, and, harmonizes compliance schedules with other rulemakings to criteria pollutants (SO2, NO x, PM) so as to maximize efficiency and minimize cost of compliance.

**DESCRIPTION:** On December 14, 2000, EPA made a "regulatory determination" under the Clean Air Act that regulation of mercury and possibly other hazardous air pollutants (HAPs) is "appropriate and necessary" for coal- and oil-based power plants. This decision automatically triggers a formal rulemaking, and EPA is scheduled to issue a proposed rule in late 2003 and a final rule in late 2004. EPA has estimated costs of a mercury control program to be about $5 billion annually, while DOE and others have estimated significantly higher costs. Members of Congress from both parties have raised concerns about the adverse consequences of mercury regulation, including impacts to the fish industry. A stringent mercury control program could impact fuel diversity and coal-based generation in the same manner as mandatory $CO_2$ reductions.

Unfortunately, the language of the regulatory determination could severely limit the Administrator's future options. EPA's designation of a specific regulatory approach – even though the regulatory determination is not a formal rule – means that *new* coal- and oil-based plants, as well as *existing* coal- and oil-based plants that are "reconstructed," will be regulated immediately in accordance with the stringent, source-by-source control program called for in the determination. Ironically, this harsh impact occurs at the outset of a multi-year regulatory process during which EPA will be attempting to establish a scientific record that justifies a stringent mercury control rule. Note that a decision today to modify the regulatory determination would neither affect the regulatory schedule, nor hinder ongoing mercury-related health effects, fate-and-transport, and emission reduction technology research critical to making sound regulatory decisions.

**STATUS:** EPA's regulatory determination was published in the *Federal Register* on December 20. The agency indicated it did not want more input on the determination, instead noting that a proposed rule will be subject to public review and comment. Legal challenges have been filed in the D.C. Circuit by the utility industry. An administrative Petition for Reconsideration also has been filed with EPA, in effect requesting the agency to withdraw that portion of the regulatory determination that prescribes a specific control program and immediately impacts new and reconstructed units.

**ISSUES:** Electric utilities are explicitly treated differently under the CAA than other major sources of HAPs, in that EPA's assessment of power plants "shall" address "alternative control strategies." However, language in EPA's determination sets in motion the regulation of mercury emissions under a strict, source-by-source control program that eliminates flexibility and use of market mechanisms. The Administrator should avoid this unnecessary limitation on possible regulatory options.

**RECOMMENDATION:** The Administrator should (1) reconsider that portion of the regulatory determination that prescribes a specific control program and immediately impacts new and reconstructed units; (2) clarify that EPA does not intend to limit regulatory options when proposing a rule; and (3) clarify further that the regulatory determination applies only to mercury and not other HAPs.

## NEW SOURCE REVIEW

**PRINCIPLE:** Initiate administrative action to ensure that the EPA's New Source Review program complements national energy policy objectives.

**DESCRIPTION**: The Clean Air Act imposes stringent "new source" control technology requirements on new units, and on existing sources if they are extensively modified. In 1996, EPA reinterpreted the new source review (NSR) program in a way that redefines when an existing source is considered to have been "modified," and issued a proposed rule consistent with this reinterpretation. EPA's approach presents an obstacle to efficiency improvement projects, safe operations and reliable generation, which is inconsistent with a sound national energy policy and the need to continue to ensure affordable and reliable electricity.[1]

In addition, EPA has initiated litigation against over 40 investor owned power plants and 10 TVA plants to force installation of new control technology on plants that EPA alleges have been modified. EPA's litigation and enforcement strategy is inconsistent with past interpretations and implementation of the NSR program.

**STATUS**: EPA has not yet finalized its proposed NSR rule, but, on December 12, 2000, the agency published a *Federal Register* notice regarding a Detroit Edison project that has national implications because it interprets the existing NSR rule to cover reliability and efficiency improvement projects. In that notice, EPA claims, contrary to the language of the current NSR modification rules, that electric utility sources must get state (or EPA) approval before undertaking necessary maintenance, repair, and replacement projects. An administrative petition has been filed requesting that the Administrator reconsider the Detroit Edison notice and confirm that EPA's 1992 WEPCo rule and pre-1996 policies remain in effect. Regarding ongoing EPA enforcement efforts, additional notices of violation and lawsuits are expected unless policy changes are initiated.

**ISSUES**: How can the NSR program be reformed to complement national energy policy objectives, and to avoid being an impediment to efficient, safe and reliable plant operations?

**RECOMMENDATION:** The Administrator should grant the Detroit Edison petition and publish notice of this action in the *Federal Register*. In that notice, EPA should confirm that the WEPCo rule and pre-1996 policies remain in effect pending a reevaluation of regulatory and policy options. The Administrator also should initiate true NSR reform. The industry is ready to work cooperatively with EPA on this effort.

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[1] See also attached discussion "Older Power Plants not Exempt from the Clean Air Act."

NEW SOURCE REVIEW SUPPLEMENT

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| **PRINCIPLE:** Contrary to environmental assertions, older power plants are not exempt from Clean Air Act requirements. |

Some in government and the public hold the belief that older plants are exempt from the requirements of the Clean Air Act (CAA) because they typically are not subject to New Source Review (NSR). To close the so-called "loophole that exempts grand fathered power plants from the Clean Air Act," EPA has attempted to redefine the meaning of (NSR) to expand its application. This is inappropriate and not necessary to protect the environment. Emissions of older plants are regulated under numerous provisions of the current Act, thus there is little rationale to regulate older plants engaged in routine operations through NSR rulemaking, enforcement actions, or legislation.

Despite nearly a tripling of coal consumption since 1970, air emissions of criteria pollutants and their precursors have been significantly reduced. In fact, total emissions per ton of coal consumed at utility plants have decreased nearly 70 percent since 1970. Much of this is due to the regulatory structure stemming from the CAA's provisions that foster compliance and emission reductions. The belief that older power plants are exempt from the CAA is erroneous.

**Significant provisions that impose (or may impose) substantial regulatory requirements on older power plants include:**

- National Ambient Air Quality Standards (NAAQS) B primary and secondary NAAQS
- Nitrous Oxides (NOx)
- Sulfur Dioxide (SO2)
- Particulate Matter (PM)
- Carbon Monoxide (CO)
- Lead
- Ozone
- Acid Rain program (annual reductions of 10 million tons SO2 and 2 million tons NOx)
- State Implementation Plans (SIPs; e.g. NOx SIP Call)
- Non-attainment area requirements B Reasonably Available Control Technology (RACT)
- Section 126 provisions B mechanism to reduce emissions that contribute to downwind non-attainment
- Protection of Prevention of Significant Deterioration (PSD) increments
- Visibility Protection Program (SO2)
- Best Available Retrofit Technology (BART)
- National Emission Standards for Hazardous Air Pollutants (NESHAP)
- Mercury Regulatory Determination
- Tall Stack Regulations -- limits emissions based on good engineering practice@ stack heights
- Toxic Air Pollution
- Maximum Achievable Control Technology (MACT)
- Residual Risk Standards
- Prevention of Accidental Releases
- Title V permitting requirements

In addition, these older facilities are subject to regulatory and reporting requirements under other statutes (e.g. CWA, RCRA, EPCRA, CERCLA). Many states also impose regulations beyond those within the Clean Air Act.

## REGIONAL HAZE REGULATIONS

PRINCIPLE: Proposed regional haze regulations should be reconsidered to conform with the clear Congressional intent which affords individual states flexibility to facilitate construction of badly needed generation facilities.

DESCRIPTION: In July 1999, EPA promulgated regulations under the Clean Air Act to address the problem of regional haze in the major national parks throughout the U.S. All relevant stakeholders have sought judicial review of the regulations. Industry has challenged the regulations on the grounds that the rule re-writes the Clean Air Act by establishing a national visibility goal (i.e., natural visibility conditions) that plainly conflicts with the carefully crafted congressional program for protecting clean air resources, ignores the D.C. Circuit's remand of the National Ambient Air Quality Standards (NAAQS) for PM-2.5 (thus elevating visibility protection ahead of health protection), and unduly constrains state discretion to develop and implement regional haze programs. Some states (West Virginia and Michigan) have challenged the rule because they believe the regulations unduly constrain their discretion, and because they, together with most other states, have not been afforded the opportunity, as provided in the Clean Air Act, to participate in Visibility Transport Commissions and to make recommendations regarding the nature and scope of a regional haze program <u>before</u> developing regional haze programs under a federal directive. Environmentalists have challenged the regulations on the grounds that the new rule does not require attainment of natural visibility conditions quickly enough.

STATUS: Review of the regional haze regulations has been held in abeyance pending action by EPA on several administrative petitions for reconsideration that were submitted in the summer of 1999. The reconsideration petitions assert that EPA adopted the regulations without statutory authority to do so and without affording the public an adequate opportunity to review and comment upon major elements of the regulations that appear in the final rule, but which did not appear in the proposed rule, including the goal of natural visibility conditions and a variety of provisions that illegally constrain state discretion. The reconsideration petitions request that EPA withdraw the regulations and re-propose them for further public comment. EPA denied two of the petitions on January 10, 2001.

ISSUES: From a general perspective, should EPA and Federal Land Managers be allowed to use the aesthetically based visibility program as a means to impose emission controls not contemplated by the other major programs of the Clean Air Act, including those designed to protect public health? More specifically, should the regional haze regulations be reconsidered to conform the regulations with the plain terms of the Clean Air Act and to ensure that, as a matter of sound public policy, the regulation of PM-2.5 proceeds, at least initially, on the basis of health-driven NAAQS rather than on the basis of the aesthetic-based visibility program?

TIMING: In the absence of a decision to reopen the regional haze rule for further public review and comment, briefing in the case will likely commence in summer, 2001.

RECOMMENDATION: Seek to stay or settle litigation of the regional haze regulations to allow for (a) public review of, and comment upon, major elements of the rule that have not previously been the subject of public comment; and (b) revisions to the existing rule, as appropriate.

## RULEMAKING TO ESTABLISH BART GUIDELINES

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| PRINCIPLE: BART regional haze requirements are not consistent with the state flexibility provisions of the Clean Air Act. |

DESCRIPTION: On January 12, 2001, EPA issued a notice of proposed rulemaking to establish guidelines that would govern how states must implement the best available retrofit technology (BART) requirements under the regional haze rule issued in July of 1999. EPA's BART proposal would severely restrict State prerogatives and burden the nation's energy infrastructure at a time when the ability of electric generators in California and other regions of the country to meet rising demand is at risk. The BART proposal is premised upon regulations that are currently the subject of litigation, but that have not yet undergone judicial review despite the fact that review was sought by industry, states, and environmental groups in August of 1999. Since the filing of petitions for review of the regional haze rule, legal proceedings have been held in abeyance pending action by EPA on several administrative reconsideration petitions, each of which asserts that EPA adopted the regional haze rule without affording the public an adequate opportunity to review and comment on major elements of the regulations, including those that pertain to implementation of the BART requirement. On January 10, 2001, only two days before EPA issued the BART proposal, EPA finally responded to two of the reconsideration petitions by denying them. EPA's delay in responding to the reconsideration petitions insured that the disputed legal issues on which the BART proposal is based would not be resolved before close of the public comment period on the BART guidelines.

STATUS: EPA's BART proposal has not yet appeared in the *Federal Register*. The Bush Administration's Regulatory Review Plan dated January 20, 2001 should ensure that the BART proposal will not appear in the *Federal Register* unless first approved by officials appointed by the Bush Administration.

ISSUES: Should EPA proceed with issuance of binding BART guidance before disputed legal issues on which the guidance is based are resolved in the pending legal challenge to the regional haze regulations? Alternatively, should EPA reconsider both the proposed BART guidance and regional haze regulations in one integrated proceeding before proceeding with litigation of the regional haze regulations?

TIMING: Absent a decision to reopen the regional haze regulations for additional public comment, briefing of the regional haze regulations is likely to commence in the summer of 2001.

RECOMMENDATIONS: Reopen the Regional Haze rulemaking to allow for (a) public review of, and comment upon, the disputed legal issues on which the BART guidance proposal and the existing regional haze rule are similarly based (and with respect to which there has not previously been adequate notice and opportunity for public comment); and (b) revisions to the existing regional haze rule as appropriate

## USE OF THE CALPUFF MODEL FOR IMPACT ANALYSIS

PRINCIPLE: Limit long-range transport modeling of the effects of new power sources to areas currently required by regulation. EPA's requirement of modeling beyond those areas is delaying construction of new state of the art clean coal power plants.

DESCRIPTION: Several companies are seeking permits to construct coal fired power plants in the Midwest using state-of-the-art technologies. These plants will be among the cleanest, most modern plants in the nation. The plants will use the best available control technology (BACT) and will have significantly lower emissions than required under New Source Performance Standards as prescribed by regulations promulgated under the Clean Air Act.

ISSUE: The National Park Service and U.S. Forest Service have proposed that plant developers be required to project the impact of the proposed plants on National Parks which are outside the impact areas covered by current regulations.

DISCUSSION: The National Park Service has asserted that these proposed plants are "large sources" relative to other power plants and is insisting that the companies use the CALPUFF model, a relatively new long-range transport model developed to predict model visibility and other impacts at a range of approximately 50-200 km from a source, even though its reliability at distances approaching 200 km and beyond is not well established. There are several reasons that CALPUFF should not be used:

- CALPUFF has not been officially recognized in federal statutes or regulations or in state statutes or regulations; [1]
- Normally, long-range transport modeling is required by EPA guidance only for distances up to 100 km except for "large sources," which has not been defined;
- CALPUFF is the subject of a current rulemaking; however, it has not been the subject of a final rule. The protocols for conducting CALPUFF modeling have not been established by regulation, and the proposed protocols may be modified by the final rule.

Federal Land Managers have an affirmative duty to protect air quality around large federal lands called Class I areas. By statute and regulation, they should have the burden of proof to demonstrate that the power plant will have a detrimental impact on Class I areas. The companies planning the project should not have the burden of proof.

RECOMMENDATION: Until the CALPUFF is required by law, its use should not be required as part of the permitting process. Projection of impacts of power plants should be limited to the areas surrounding the plant as defined by current regulation.

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[1] In one case, the Kentucky Division of Air Quality has concluded that the developer is not required to run the CALPUFF model as part of the permitting process. The Federal Land Mangers ("FLMs") indicate they believe the Kentucky plant, for example, could have a detrimental impact on air quality in the "affected" Class I areas: Linville George Wilderness Area and Great Smoky Mountain National Park. The closest borders of the Class I areas are approximately 200 km from the proposed power plant. However, the FLMs have not provided supporting documentation. They argue that Kentucky Division of Air Quality must compel the developer to run a CALPUFF screen in order to "prove them wrong."

THE IMPORTANCE OF FUEL DIVERSITY IN ESTABLISHING A NATIONAL ENERGY POLICY AND A SOUND CLIMATE CHANGE STRATEGY

PRINCIPLE: United States' climate policy, recognizing the global nature of the issue, should be based on voluntary, flexible, inclusive and cost-effective approaches to reducing greenhouse gas emissions. Climate policy should promote the principle of fuel diversity and be complementary to the national energy policy. Climate policy should promote development and global use of more efficient technologies and be designed to promote economic development in the United States and throughout the world. Policy should support an accelerated scientific research program. Voluntary programs should establish incentives for improved energy efficiency and encourage participation and reporting. US climate policy should reject regulation of, or specific reduction targets or caps on, emissions of CO2 or any other greenhouse gas.

The U.S. economy is highly dependent on affordable electricity. Since 1970, electricity growth has closely tracked the rise in GDP. To meet increased demand and to offset retirements of existing power plants, the Department of Energy forecasts that 1,310 new power plants – with 393 gigawatts of capacity – will be needed by 2020.[1] A sound national energy policy is needed to continue to ensure the affordability and reliability of electricity, and to meet future energy demands.

The Coal-Based Generation Stakeholders (CBGS) group, of which National Mining Association is a member, believes that fuel diversity – coal, natural gas, nuclear energy, oil, hydropower and other renewables, to generate electricity – must be maintained as a matter of national energy policy and national security. An energy policy that maintains fuel diversity can appropriately balance continued utilization of coal, the most essential fuel for reliable and affordable electricity, with a sensitivity to the climate change issue that reflects both economic and environmental objectives.[2]

The industries that comprise CBGS have long supported voluntary, flexible, cost-effective and inclusive approaches to reducing greenhouse gases.[3] For example, under the Climate Challenge program, the electric utility industry was projected to reduce 174 million metric tons of carbon dioxide ($CO_2$)-equivalent greenhouse gases in 2000. The electric power industry is currently developing a voluntary climate initiative that would serve as an extension of the Climate Challenge program. The industry expects to partner with the federal government – particularly the Department of Energy – and other

[1] Energy Information Administration (EIA), "Annual Energy Outlook 2001 with Projections to 2020" (Dec. 2000).

[2] Coal-based generation is increasingly clean. Since 1970, coal-based electric generation has increased 234 percent and coal use in power plants has increased 270 percent, yet criteria pollutant emissions have steadily declined. EIA, "Annual Energy Review 1999."

[3] "Voluntary" recognizes that the climate change issue merits policy responses that explore economically sustainable measures should any legally binding agreement to address greenhouse gases be adopted. Full "flexibility" encompasses emissions trading, project-based offsets, forestry and soils projects, and banking, which will be critical in the event of any domestic or international agreement. "Inclusive" encompasses all greenhouse gases; all sources and sinks; and all locations, domestic and international. "Reduce" means reduce, avoid, sequester or otherwise mitigate greenhouse gases, whether domestically or internationally.

industries to pursue approaches to further reducing greenhouse gases. This initiative will reduce greenhouse gases in the near term, and promote a technology research, development and deployment (R, D & D) program that will lead to the development of cost-effective options to reduce greenhouse gases.

CBGS supports continued scientific research to evaluate if human activity is adversely affecting the climate, and, if so, to evaluate the causes, costs, policies and adaptation strategies to address possible solutions. Consistent with the President's March 13 letter to several Senators, CBGS opposes ratification of the Kyoto Protocol because it would cause serious harm to the U.S. economy and lacks binding commitments for all nations. Also consistent with the President's letter, CBGS strongly opposes regulation of $CO_2$ or any other greenhouse gas as a pollutant under the Clean Air Act or other legislation.

Because there is currently no cost-effective control technology for greenhouse gas emissions, compliance with stringent, mandatory targets and timetables such as those contained in the Protocol would cause massive fuel switching in the electric utility industry from coal to natural gas,[4] which would be enormously expensive and dramatically increase electricity prices,[5] and which would further exacerbate the fuel diversity issue. A Kyoto Protocol-type scenario would also raise serious problems in natural gas supply, prices and infrastructure, and would cause significant job losses in CBGS industries and among our suppliers. Stringent targets and timetables other than those contained in the Protocol also could be harmful to our nation's economy and energy policies. Moreover, they could have a chilling effect on badly needed investment in new coal-based generation because of a legitimate concern that such investments would become stranded in the event legally binding regulations were imposed in the future.

As currently envisioned, a sound voluntary climate initiative would consist of three major elements:

1. In the short term, the climate initiative is expected to achieve credible, verifiable emission reductions or offsets of greenhouse gases facilitated by certain policies and incentives from the federal government, including those that encourage full flexibility for emission credit and trading programs.

2. Further reductions of greenhouse gases in the medium to long term would result from the development and application of more energy-efficient, cost-effective electricity supply options, such as clean coal technology and renewables, that allow for a reliable and affordable supply of energy.

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[4] See, *e.g.*, the reference study that demonstrates that under a Kyoto Protocol-type scenario, coal would decline from 50 percent of electric generation to as low as 13 percent in 2010, while natural gas would rise from 25 percent to 50 percent in the same time frame. Research Data International, Inc., U.S. Gas and Power Supply under the Kyoto Protocol, Vol. I at 1-9 (Sept. 1999).

[5] A recent EIA report (which actually understates costs because mercury has not yet been analyzed) found that reductions in sulfur dioxide, nitrogen oxides and $CO_2$ consistent with recent legislative proposals would increase electricity prices by 17-33 percent in 2005, and by 30-43 percent in 2010. EIA, Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides and Carbon Dioxide xvii, 27 (Dec. 2000). The bulk of the cost increases are due to $CO_2$ restrictions.

3. A climate technology R, D & D program is needed to ensure that cost-effective technologies are developed in the long term. This program should complement overall U.S. energy policy and the Framework Convention on Climate Change.

   - In accordance with legislation introduced in the 106th Congress – such as S. 882, S. 1776, S. 1777 and S. 3253 – and public-private studies,[6] the R, D & D program could focus on 1) advanced technologies in electric generation and transportation, 2) cost-effective direct carbon capture and removal from powerplant and other emission sources, and 3) carbon sequestration in natural "sinks" such as forests, soils and oceans.

   - Two program goals could be to 1) fast track such climate technologies to market, and 2) promote export of such technologies overseas, particularly to developing countries such as China and India that could greatly benefit from more energy-efficient electric generation technology.

   - In partnership with the federal government, the climate initiative would be expected to adequately fund the climate technology R, D & D program and to provide appropriate financial incentives, with periodic reassessment. Industry partners that install new climate technologies would be interested in recouping any substantial investments over a reasonable period of time.

The climate initiative should be consistent with government policies that encourage full flexibility, both domestically and internationally, in emissions trading, project-based offsets, forestry and soils projects, and banking. Financial and policy-oriented government incentives should be explored as a means to jump start credit and trading programs, offset projects, and the climate technology program.

Development of a voluntary climate initiative presents an opportunity not only for innovative emission reduction programs, but also for the inclusion of a broader number of partners involved in the life cycle of coal-based generation. For example, credit could be given to environmental improvements from extracting coal at the mine and delivering it to the generator.

CBGS believes that a climate change strategy premised on a voluntary climate initiative would achieve both environmental and economic objectives, and would help maintain fuel diversity. The strategy would reduce greenhouse gases in the short term as technological responses are developed for long-term availability, all the while maintaining the viability of coal as a vital component of electric generation. In short, environmental policy would complement energy policy, which is consistent with the President's goal of ensuring that global climate change issues are addressed "in the context of a national energy policy that protects our environment, consumers, and economy."

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[6] See, *e.g.*, Battelle's Global Energy Technology Strategy – Addressing Climate Change (2000).

## COAL PRODUCTION

- The Coal Mine Valley Fill Issue
- The Forest Service Roadless Area Conservation Rule Will Eliminate Coal Reserves from Development
- The Powder River Basin Resource Development Act of 2000
- Coal Leasing – The Need for an Orderly, Predictable Process
- Advance Royalty Payments in Lieu of Continued Operations
- Revitalizing the Abandoned Mined Lands Program
- MMS Administrative Appeals Process
- U.S. Forest Service Management Plan Revisions
- Regulation of Diesel Particulate Matter Exposure in Underground Metal/Nonmetal Mines
- Black Lung Disability Benefits Program Final Regulation Employment Standards Administration

**THE COAL MINE VALLEY FILL ISSUE**

**PRINCIPLE:** Support coal industry operations and employees in Appalachia by adopting proposed rules that clarify the scope of, and remove the ambiguities in, the Clean Water Act Section 404 program with respect to excess spoil. Delays in adopting these rules are restricting coal operations in Appalachian states at a time when coal is needed to provide fuel for affordable electricity.

**DESCRIPTION:** In October 1999, a federal district court in West Virginia stunned the Nation's coal industry with a decision barring the longstanding practice of building valley and hollow fills to dispose of the dirt and rock generated during coal mining. *Bragg v. Robertson*, 72 F. Supp. 2d 642 (S.D. W.Va. 1999), *appeal pending*, No. 99-2443 ($4^{th}$ Cir). Notwithstanding the fact that these engineered fill structures are both a necessary part of coal mining operations and expressly authorized by federal laws regulating coal mining, the court interpreted regulations issued under those laws as prohibiting their construction in hollows and valleys that inevitably contain stream courses. While the decision remains pending on appeal, the past Administration abandoned the working men and women of America's coal industry and announced that it now agreed with the court's view. The past Administration's action in this regard is not only contrary to the laws it administers, it will have economic consequences. A Marshall University study concluded that the effects in West Virginia alone would be as great or greater than those of the Great Depression.
Earlier in the same litigation, the federal agencies, the Environmental Protection Agency, Office of Surface Mining and the Corps of Engineers (EPA, OSM & COE), settled the claims related to the use of section 404 permits to authorize these fills under the Clean Water Act (CWA). The agencies agreed to conduct a programmatic Environmental Impact Statement that addresses environmental and economic consequences of different actions, as well as evaluates the better coordination of overlapping regulatory programs.

**STATUS:** The appeal in the $4^{th}$ Circuit has been briefed and was argued on December 7, 2000. In the meantime, the EPA, OSM and COE are preparing a Draft EIS. EPA and COE also have pending a proposed rule published on April 20, 2000 clarifying that excess spoil is fill material subject to section 404 and not section 402 of the CWA. This rule would remove the ambiguity in the agencies' programs that the district court relied on to reach its erroneous conclusion that these fills as well as other activities that have the effect of displacing waters of the United States are not authorized by section 404.

**DECISION:** Should any part or form of a Draft EIS be publicly released before the completion of the underlying technical, economic and other studies.
**RECOMMENDATION:** Delay public release of the Draft EIS in any form until all the underlying studies are complete and have been subject to some form of peer review. This is completely defensible and will assure that the EIS process on this matter will not be subject to criticisms related to its credibility and integrity.

**DECISION:** Should EPA and COE adopt, as a final rule, the proposal clarifying the scope of the section 404 program with respect to excess spoil and other activities that have the effect of replacing waters of the United States.
**RECOMMENDATIONS:** 1) Proceed to adopt as final the proposed rule published on April 20, 2000. The rule is an important part of maintaining the integrity of the 404 program by clarifying a longstanding ambiguity that has caused grave uncertainty for the regulated community and the agencies. It not only addresses the excess spoil issue but other activities as well, e.g. landfills, OR 2) Await the decision of the $4^{th}$ Circuit to determine whether it would require any modification of the proposal to address the central features of the rule. At some point, the EIS on mountaintop mining will have to analyze how excess spoil fills are to be addressed within the prevailing regulatory schemes under the CWA and SMCRA and whether any conflicts exist.

## THE FOREST SERVICE ROADLESS AREA CONSERVATION RULE WILL ELIMINATE COAL RESERVES FROM DEVELOPMENT

**PRINCIPLE:** Implementation of the Forest Service Roadless rule will preclude development of the energy resources, including coal, that are located on these lands. The rule must be modified through administrative action or through existing litigation so that resource development is not precluded.

**BACKGROUND:** In January 2000, the Clinton Administration declared 58.5 million acres of Forest Service land off limits to mineral development by prohibiting road construction and reconstruction activities, including even temporary road construction on lands subject to this rule.

The Department of the Interior (DOI) is the largest owner of western minerals, while the U.S. Forest Service (USFS) in the Department of Agriculture is responsible for the management of the surface. Under the roadless rules, the actions of the surface owner will have a profoundly negative impact on the development of coal, oil and gas found under these lands. This is particularly important as 90 percent or more of the increase in coal production through 2020 is expected to come from federal lands including lands affected by this rule.

**IMPACTS:** As stated in the Final Roadless Environmental Impact Statement (EIS), several serious impacts have been identified, including: "...preclude future development of leasable minerals within inventoried roadless areas...[which would result in] decreases in jobs, income, and payments to states." The Department of Energy found that both expansion of existing mines, and tracts of coal of near term commercial interest will be affected.

Among all of the multiple users of the National Forest, coal mining has the distinct and unique requirement – pursuant to the terms of the Surface Mining Act – to restore all surface disturbances to at least as good a condition as the pre-mining condition. This requirement applies to all roads developed in conjunction with exploration or development activities. In short the Surface Mine Control and Reclamation Act already provides the protections the roadless rule purports to safeguard.

**EXAMPLES:** Two areas of federal coal production have been specifically identified as being impacted by this rule: the Manti-La Sal National Forest in Utah and the Grand Mesa, Uncompahgre, and Gunnison (GMUG) National Forests in Colorado. The impact on the West Elk Mine, located in the GMUG National Forest is discussed as an example. This underground coal mine, which produces about seven million tons of high BTU, low sulfur federal coal per year, is located in western Colorado's North Fork Valley – the fastest growing coal producing region in Colorado. The mine employs about 360 people and has an annual payroll of $26 million. Just over 93% of West Elk's coal is shipped to eastern utilities which need its unique quality characteristics to meet Clean Air requirements. The West Elk mine will be significantly and adversely impacted by the Roadless Area designation in several ways:

- As existing coal leases are modified or renewed, they will become subject to the roadless area prohibitions;
- The roadless boundary includes adjacent areas of unleased federal coal reserves. That would be excluded from potential development since necessary exploration drilling and mine development would be prohibited;
- Approximately $3 billion of federal coal could be impacted by the Roadless Area rule in this one area alone.

**RECOMMENDATIONS:** The Energy Task Force must consider the effects of this rule on development of resources needed to meet future energy demand. Should the rule go into effect, the Administration should actively engage in the litigation to assure that final settlements do not preclude resource development.

## THE POWDER RIVER BASIN RESOURCE DEVELOPMENT ACT OF 2000

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| PRINCIPLE: Enact legislation that provides for orderly development of all energy resources located on federal lands to ensure that development of one resource does not preclude economic development of a co-located resource. |

BACKGROUND: In the 2nd Session of the 106th congress, the entire Wyoming delegation sponsored legislation (The Powder River Basin Resource Development Act of 2000 - S. 1950 and H.R. 4297) to resolve conflicts between oil and gas and coal developers which arise as a result of simultaneous resource development on federal lands in the Powder River Basin (PRB) of Wyoming and Montana. The proposed legislation (as reported by the Senate Energy Committee) was the result of lengthy negotiations between the Administration, coal producers and oil and gas developers. Unfortunately, on December 15, 2000 the Clinton White House insisted that the bill be excluded from the Omnibus Appropriations package, thus preventing passage and leaving an uncertain future to coal, coalbed methane (CBM) and oil and gas production in the PRB.

THE PRB of Wyoming and Montana is one of the world's most productive energy resource regions. It contains the largest reserves of low sulfur coal in the United States. Coal mined in Campbell County, Wyoming itself now represents approximately 1/3 of all U.S. coal production. The PRB is also rich in oil and gas, including CBM that lies within and adjacent to the coal seams. Virtually all of the coal and approximately 50% of the oil and gas in the PRB is owned by the federal government and managed by the BLM, under the Mineral Leasing Act of 1920.

ISSUE: The BLM has issued and continues to issue separate federal coal leases and federal oil and gas leases for the same locations in the PRB. In those areas leased both for coal and for oil and gas (common areas), disputes over timing of mineral development have arisen. The sequence of development in the common areas frequently becomes a critical issue. No clear statutory direction exists to resolve disputes over the sequence of mineral development.

LEGISLATIVE SOLUTION: Last session's negotiated Senate legislation would provide the missing statutory direction to resolve these mineral development disputes and would establish a formal procedure to be used only in the conflict areas of the PRB. By its expressed terms, the bill would have no impact whatsoever outside the PRB.

The bill would require competing mineral developers to negotiate first, and urges the BLM to use its regulatory authority to achieve a possible resolution to each conflict. If both negotiations and regulatory efforts fail, either the coal developer or the oil and gas developer could invoke the formal resolution process established by the legislation by filing a petition in the local federal district court and with the Secretary of the Interior. The bill's process then would require a public interest determination first by the Secretary, then by the court, as to which mineral will be developed first. There would follow a temporary suspension or termination of rights to develop the conflicting mineral. The court, with the aid of an expert panel, would determine the amount to be paid to the non-prevailing mineral developer.

RECOMMENDATION: The Bush/Cheney White House should encourage early passage and enactment of legislation similar to S. 1950 as approved by the Senate Energy Committee in the 106th Congress. Until such legislation is passed, conflicts involving simultaneous development of competing fossil fuel resources in the PRB will continue to threaten or delay orderly development of much needed environmentally favorable domestic energy resources.

## ADVANCE ROYALTY PAYMENTS
## IN LIEU OF CONTINUED OPERATIONS

PRINCIPLE: Legislation is needed to provide greater flexibility in the way that requirements for payments of advanced royalties are implemented.

BACKGROUND: On August 4, 1976, the Federal Coal Leasing Act Amendments (FCLAA) were enacted. Section 6 of the FCLAA inserted a new Section 7(b), providing, in part, that the Secretary, upon determining that the public interest will be served thereby, allow the coal operator to pay advanced royalties rather than require continued operation of a mine.[1]

The current "advance royalty" provisions provide that:

- Advance royalties may be paid in lieu of the statutory obligation to maintain continued operations, but that they may not be paid for more than an aggregate of 10 years;
- Advance royalties paid during the initial 20-year term of the lease may not be carried over past the twentieth year of the lease; and,
- The Secretary may unilaterally cease to accept advance royalties and require that production continue.

ISSUE: Based upon experience since 1976, the current statutory provisions are counterproductive as these provisions do not give the coal operators the flexibility needed to be able to react to changing market conditions. If market conditions are such that coal is in "over supply", the operator needs the flexibility to slow or stop production for a period of time. Conversely, when coal demand increases the operator needs the flexibility to expand production.

RECOMMENDATIONS: Federal legislation is needed to provide operational flexibility for Western coal operators. Such legislation will also promote the ultimate recovery and conservation of federal coal. While limited to scope, the following amendments to provide operational flexibility to the current lease holders:

- Extend the aggregate authority pay advance royalties in lieu of continued operations from 10 years to 20 years;
- Provide that advance royalty payments are based on the average sales price for coal sold in the spot market from the same region during the month in which the request to pay advance royalties is submitted to the BLM;
- Delete the current prohibition on the carry-over of advance royalty payments made during the initial 20-year period of the lease;
- Delete the current unilateral authorization for the Secretary to cease to accept advance royalties in lieu of continued operations; and
- Delete the last sentence of Section 39 of the MLLA of 1920 (Section 14 of FCLAA) prohibiting the waiver, suspension or reduction of advance royalties.

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[1] This provision requires that leases produce one percent of a mining unit's recoverable reserve each year.

## REVITALIZING THE ABANDONED MINED LANDS PROGRAM

PRINCIPLE: Work with industry to reform the Abandoned Mine Land program to ensure that funds are effectively used to complete reclamation work outstanding so that the program can come to a successful conclusion thus meeting SMACRA's original environmental goals.

DESCRIPTION: The 1977 Surface Mining Control and Reclamation Act (SMCRA) mandates that lands disturbed by coal mining be restored to their pre-mining condition. The Act addresses mining sites inactive before 1977 through the Abandoned Mine Land (AML) provisions. SMCRA requires coal operators to pay a fee to the Office of Surface Mining's AML Fund to clean up pre-law abandoned sites. The fee was set at 35¢ per ton for surface mined coal, 15¢ per ton for underground coal and 10¢ for lignite and has been extended twice, most recently in 1992. The fee is levied exclusively on coal production; no other mineral pays an AML fee. The fee is set to expire at the end of FY-2004.

In 1992, interest from the AML Fund was set aside to pay for the health benefits of certain retired coal miners and their widows under the Coal Industry Retiree Health Act.

STATUS: There is a mismatch between the amounts paid into the fund and the amount used for reclamation. To date, $5 billion in contributions have been paid by the coal industry into the AML Fund but only $1.3 billion in Priority 1 and 2 reclamation work has been completed.

Approximately $2.5 billion in Priority 1 and 2 coal reclamation work remains to be completed, yet the AML Fund has an unappropriated balance of $1.5 billion. This mismatch reflects annual appropriations have been significantly less than the fees paid by the industry and a distribution formula that does not reflect an effective use of the fees collected.

There are excessive federal and state administrative expenses of approximately $45 million annually.

RECOMMENDATION: The coal industry believes that 2001 provides a unique opportunity to reform the AML program. The coal industry is prepared to support an extension of the AML fee, *if* the additional funds are dedicated to the clean up of the remaining Priority 1 and 2 projects, and **only *if*** the current fee structure is reduced beginning in FY-2002. The fee structure would be the subject of negotiation. Suggested program reform should include a major reduction in administrative costs and a freeze on the inventory of eligible reclamation projects. Legislation to support these recommendations should be introduced in 2001 to give long-term financial stability to the various state AML programs. The proposed changes in the program would ensure that the SMACRA's original environmental goals are achieved and that reclamation is completed more quickly and effectively.

## MMS ADMINISTRATIVE APPEALS PROCESS

DESCRIPTION: In 1973, the Department of the Interior (DOI) promulgated administrative procedures for the appeal of final orders and decisions of officers of the Minerals Management Service (MMS), directing that appeals would be made to the Director of MMS. The MMS is the only DOI agency with an intermediate appeal to the Director of the agency. All other DOI agency appeals go directly to the Interior Board of Land Appeals (IBLA).

In 1995, the DOI established the Royalty Policy Committee (RPC) to provide advice to the Secretary on the management of Federal and Indian mineral leases, revenues, and other minerals-related policies. The RPC includes representatives from states, Indian tribes and allottee organizations, minerals industry associations, other Federal agencies, and the public. At its first meeting in September 1995, the RPC established eight subcommittees, including the Appeals and Alternative Dispute Resolution (ADR) Subcommittee (Subcommittee). In February 1997, the Subcommittee submitted a consensus report for consideration by the RPC.

ISSUE: The Subcommittee agreed that the principal purpose of the MMS administrative appeals process should be the expeditious and independent review of cases involving disputed facts, legal issues, or policy upon request of the adversely affected party. The Subcommittee recognized that the MMS appeals process has been under criticism and serious review since 1991 and that substantial reform is needed.

While the Subcommittee was working, the Federal Oil and Gas Royalty Simplification and Fairness Act was enacted, establishing among other provisions, a 33-month time limitation for the DOI to make final decisions on appeals involving royalties due on federal oil and gas leases. This provided a further impetus to the Subcommittee's efforts to reduce the overall time for making final DOI decisions on appeals. In addition, MMS proposed a draft regulation that would place a 16-month time limitation on the MMS appeals process, leaving the rest of the 33-month period for review at the IBLA. The Subcommittee strongly urged that the recommendations in its report be substituted for MMS's proposed regulation.

The Subcommittee developed a number of specific steps involving both the appeals and ADR processes, incorporating them into a one-stage IBLA administrative appeal process. In March 1997, the RPC approved the Subcommittee report and forwarded it to Secretary Babbitt for his consideration. By letter dated September 22, 1997, Secretary Babbitt informed the RPC that he largely agreed with the report's recommendations. However, by Memorandum dated June 1, 2000, to the MMS Director, Secretary Babbitt stated that contrary to the RPC's recommendation, he had decided to retain the current two-tier appeals procedures.

RECOMMENDATIONS: The DOI should initiate administrative procedures which implement the Subcommittee's one-stage royalty appeals' recommendations. Otherwise, mineral developers that disagree with MMS decisions will continue to be subjected to a two-stage process which can extend administrative appeals from five to seven years, even before its controversy can enter the courts.

## U.S. FOREST SERVICE MANAGEMENT PLAN REVISIONS

**BACKGROUND:** On a regular basis the U.S. Forest Service (USFS) reviews and, as necessary, revises its Forest Service Management Plans. Over the last year, the proposed revisions to various management plans have steadily moved away from a multiple use concept in favor of a position that favors conservation and recreation and disfavors mining and development. Currently, the USFS is proposing to revise the Thunder Basin National Grasslands management plan. The Thunder Basin National Grasslands is home to the largest coal producing region in the United States – the Powder River Basin of Wyoming (PRB). This region now produces a third of the nation's coal supply and in this time of high and unstable energy prices is a source of reliable, low cost, environmentally friendly coal. Pending lease sales of nearly 2.3 billion tons of mineral resources are in areas that would be affected by the revision. Availability of these reserves is necessary to continue long term operations at existing mines.

**ISSUE:** The proposed revision to the Thunder Basin National Grasslands management plan includes the establishment of a new wilderness area (pending Congressional approval) and other "special interest areas." These areas would likely trigger requirements that are more stringent than necessary to protect air quality and air quality related values (flora, fauna, etc.). The coal industry is one of the most heavily regulated in the country, and the PRB in particular more air quality monitors per square mile than any other region of the United States. There has never been a monitored violation of the $PM_{10}$ (particulate matter less than 10 microns in size) National Ambient Air Quality Standard in this area. However, the demonstration for protection of air quality would not be based on data from actual air quality monitors, but rather would be based on hypothetical computer models that significantly over-predict emissions.

Unfortunately, these specially designated areas are located 5 to 35 miles downwind of existing coal mining operations in the PRB. As new federal coal leases are issued and as coal operators apply for air quality permits, these specially designated areas have the very real potential of impacting the ability to permit new areas or limiting production of existing operations.

A further Federal Land Managers' proposal would authorize the creation of areas where threatened and endangered species could be re-introduced. In this case, these areas are located immediately east of the existing PRB coal mining operations and would be used to re-introduce black-footed ferrets. There is no discussion of the impact to the mining operations should these animals migrate onto the minesites.

**RECOMMENDATION:** Revisions to the Forest Service Management Plans should be undertaken in concert with all relevant federal agencies, including the Department of Interior, and should be structured to assure continued access to coal resources on federal lands.

REGULATION OF DIESEL PARTICULATE MATTER EXPOSURE IN UNDERGROUND METAL/NONMETAL MINES

**DESCRIPTION**: In 1998 the Mine Safety and Health Administration (MSHA) published two proposed rules intended to reduce the exposure of miners to the constituents of diesel fuel combustion in underground mines - one for underground coal and one for underground metal/nonmetal (m/nm). The proposals, while similar in intent, departed dramatically on the options available to mine operators to comply with the proposals. Moreover, the rules proposed for m/nm mines the use of unproven sampling technology and the application of yet unproven and not commercially available for mining applications, after-treatment control technology. It is important to note that concerns regarding both the sampling technology and the availability of after-treatment control technology were raised during the public comment period by the National Institute for Occupational Safety and Health (NIOSH), mining research branch, the principal federal government mine safety and health research authority.

**STATUS:** The coal and m/nm proposed rules were forwarded to the Office of Management Budget for final approval on December 11 and 14, 2000 respectively. OMB approved the final regulations on January 8, 2001 for publication. The final rules were published on January 19, 2001. They were to become effective on March 20, 2001; however, they were extended until May 20, 2001 under the President's regulatory review directive.

**ISSUE**: Should The Department of Labor//MSHA, depending upon the effective date of the regulations, re-propose or stay the m/nm regulations in order to reevaluate the scientific, technologic and economic basis upon which the previous Administration proposed and finalized the regulations.

**RECOMMENDATION**: Immediately stay the rules and re-propose them in order to seek additional public comments and consideration by new Administration.

## BLACK LUNG DISABILITY BENEFITS PROGRAM FINAL REGULATION EMPLOYMENT STANDARDS ADMINISTRATION

**DESCRIPTION:** On December 20, 2000 the Department of Labor (DOL) issued final regulations that make sweeping changes to the Federal Black Lung Disability Benefits Program. The regulations were to be effective January 19, 2001. Despite extensive medical, economic and other evidence that the proposed regulations were severely flawed, DOL published the final rule. Unprecedented criticisms of the proposed rules were filed by the American Bar Association, Members of Congress, independent medical societies, and many others. The regulations will have significant economic impact on the coal mining and insurance industries (between $3.3 billion and $7.2 billion according to reputable estimates). Moreover, DOL concedes in its economic analyses that small coal mines will be closed with subsequent loss of jobs. Nonetheless, DOL summarily ignored the substantive objections, informed criticisms, and negative economic implications of the proposed regulations.

**STATUS:** On December 22, 2000 NMA and other parties filed a legal challenge to substantive parts of the final rules. The complaint charges that the final regulations violate the rights of litigants, create illegal presumptions, are arbitrary, capricious, inconsistent with existing laws, and violate the US Constitution. A preliminary injunction was granted on February 8, oral arguments are set for May 21.

**OPTIONS:**

1) If filed, consent to plaintiff's motion for summary judgment and remand of the final rules for reconsideration by the Secretary, or

2) Immediately propose to stay the effective date and re-propose the regulations in order to evaluate the previous Administration's motives to promulgate such severely flawed and economically damaging regulations, or

3) Engage in settlement discussions with the plaintiffs and consent to substantive settlement offer proposed, by plaintiffs, or

4) Continue with the litigation allowing the possibility of all evidence being open for full disclosure in the court, possibly to the enforcement of the Department and harmful to some employees.

**RECOMMENDATION:** Permit the regulations to be vacated and remanded by consenting to plaintiff's possible or propose to stay and re-propose the regulations.

## CROSSCUTTING

- Federal Government Coal Research Programs
- Modifications in Corporate Income Tax Policies
- Reliable, Timely and Complete Energy Data
  A Requirement for Sound Public Policy

## FEDERAL GOVERNMENT COAL RESEARCH PROGRAMS

PRINCIPLE: Support federal coal research programs that: accelerate demonstration of technologies; develop advanced technologies that are focused on greater efficiency and environmental improvement for coal generation; focus research on carbon sequestration technologies; improve mining efficiencies, safety and environmental performance; and, advance mining education.

DESCRIPTION: Federal government coal research programs related to coal utilization and mining (production) are centered within the Office of Fossil Energy, Department of Energy. The National Energy Technology Laboratory coordinates much of the research; some basic research is conducted through the other national laboratories. Most of the research programs are designed as industry-government partnerships with industry providing half or more of the cost of the research. The Fossil Energy program also supports academic research that increases our fundamental understanding and provides for undergraduate education and graduate research on coal utilization systems, but lacks a equivalent program for academic coal production (mining and mineral preparation) research.

Coal Utilization Research Program

The goal of the coal utilization research program systems research program is to develop advanced technologies that increase the efficiency and improve the environmental performance of coal use, principally for the production of electric power and liquid fuels. Among the key DOE programs are the following.

- The Clean Coal Technology Program (CCT) was begun in 1985. Thirty eight projects with a total value of $5.2 billion have been funded, and two-thirds of the funding - $3.5 billion – has been from industry. Many new and successful technologies were developed through the CCT program including the NOx reduction technologies that are now in commercial use on 75% of the coal fired power plants in operation today. Technologies demonstrated include advanced electric power generation systems, environmental control devices and pre-combustion technologies. This program is nearing completion.
- The Power Plant Improvement Initiative (PPII) program accelerates the demonstration of near-commercial technologies that can be installed on existing coal-fired power plants to improve their efficiency and environmental performance. In the FY 2001 appropriations, Congress directed DOE to use $95 million in unspent CCT money to begin the PPII. The initial PPII projects will be selected by the end of FY 2001. The program requires a minimum of 50% in industrial cost-sharing.
- The DOE Office of Fossil Energy, through its Coal and Power Systems program, conducts coal related R&D, including advanced coal gasification and combustion systems, materials development, environmental assessments of coal use, development of mercury control technology, management of solid byproducts from coal combustion, and production of ultraclean liquid fuels. Many of these program elements are combined in and support the Vision 21 concept, which seeks to integrate promising new technologies into highly efficient, low-emitting energy complexes, for the production of electricity, fuels and chemicals.
- A critical element of the Coal and Power Systems program is research on carbon sequestration. If reductions in carbon dioxide emissions from coal-based electricity generating systems become necessary, sequestration may become the only practical, long-term solution. In the near-term, it is essential to know the technical and economic feasibility of a variety of sequestration options to guide public policy. For that reason, it is essential that the DOE program be funded at a level sufficient to

move beyond current lab-scale research to practical field tests of the most promising options.

- The UltraClean Fuels program is developing new approaches to producing liquid transportation fuels from coal to meet increasingly stringent environmental standards, while reducing our dependence on imported petroleum and natural gas. An important aspect of the Clean Fuels program, is the integration of fuels production with advanced electric power generation systems (as in the Vision 21 concept) to allow the efficient coproduction of a variety of energy products from a single facility with coal as the ultimate fuel source.

Mining – Production

The Mining Industry of the Future program is a joint industry/DOE to develop technology that improves the production and processing of minerals, including coal. The goal is to develop new technologies that ensure the health and safety of employees, protect the environment, reduce energy consumption in mining, and produce high quality products at lower costs. Research is being conducted in three areas: exploration, mining and processing. To date 26 projects have been funded with the first results of this pre-commercial research expected in late 2001. The program has been funded at $3 million per year with matching funds from industry.

The DOE provides little support for research on mining at the academic institutions. This diminishes the national capability to develop fundamental science to improve mining practices, and impairs the abilities of the universities to train future generations of mining engineers. In addition to its programs in oil and gas production, the Fossil Energy office should institute a program to support academic research in mining.

RECOMMENDATIONS:

Coal Utilization: DOE's requests for the current coal utilization research and development programs should be fully funded, and the Power Plant Improvement Initiative should be continued at an annual funding level of $150 million . The DOE Vision 21 program should be established as a separate budget item so that its goals can be prioritized and accelerated. Coal and Power Systems research and development should be focused on supercritical and ultra-supercritical plants, advanced gasification and combustion hybrid systems. Funding for $CO_2$ sequestration should be increased to allow field testing of promising options. Research should address the three criteria pollutants ($SO_2$, $NO_x$ and mercury), solid waste and water management. DOE should organize research programs in accordance with the priorities identified by the coal and utility industries as defined in the Technology Roadmaps developed by the Coal Utilization Research Council, the Electric Power Research Institute and the Coal Based Generation Stakeholders Group.

Coal Production: The DOE request for Mining Industry of the Future funding should be increased to a minimum of $10 million annually. A program of university mining research should be established under the Office of Fossil Energy with an initial annual funding of $3 million to support academic research and graduate studies in mining.

Coordination: DOE should ensure that the mining related research currently being carried out in many locations within the department under different programs is coordinated and is not duplicative. This could be done by establishing a "coal center" at NETL but coordination should not require additional staffing.

## MODIFICATIONS IN CORPORATE INCOME TAX POLICIES

PRINCIPLE: Modify federal tax policy to encourage investment in production of domestic energy and in electric generating facilities.

DESCRIPTION: Tax policy, including tax incentives, can be a major component of energy policy as they affect the development and production of energy including electricity. Several provisions of the Internal Revenue Code should be modified to address counterproductive policies previously put into place. These issues are also of significant importance to the oil and gas industry. At a minimum, any modifications to the areas of tax law outlined below which are accorded to one fuel should be similarly accorded other fuels in order to maintain a level playing field for attracting investment.

RECOMMENDATIONS:

- As identified in a separate paper, the most important changes in tax policy to address the nation's energy supply deficit – specifically electricity – are the investment tax credit and production tax credit components of the National Electricity and Environmental Technology (NEET) legislation. These incentives will provide the impetus to increase the supply of electricity; improve the environment through reductions of pollutants regulated under the Clean Air Act, and reduce the amount of carbon dioxide emitted per unit of energy produced through significant increases in the efficiency of converting coal to electricity.
- The <u>corporate alternative minimum tax</u> (AMT) should be repealed or modified. Mining is a capital-intensive business and the AMT works a hardship on such businesses. As measured by generally accepted accounting principles, most mining companies are not profitable. In recent years, most companies have been consistently unprofitable. The fact that mining companies are required to pay the AMT, even if they have no profit, has added to the difficulty of attracting capital to maintain, expand or construct new mines. While elimination of the AMT may not be politically or economically achievable in the near term, at a minimum, legislation should be supported to allow historical corporate AMT taxpayers, such as mining, to utilize accumulated AMT tax credits to offset prospective AMT tax liability. Legislation to effect such a change was enacted by the previous Congress, but was vetoed as part of a larger tax package by President Clinton. Separately, eliminate the 90 percent limitation on use of net operating losses and foreign tax credits applicable to corporate AMT taxpayers.
- Mining companies should be provided the opportunity to fully expense <u>exploration and development costs</u> just as the oil and gas industry. The current limitations on expensing result in mining companies being forced to capitalize a percentage of their exploration and developments costs. This tax treatment serves as a financial disincentive for the development of new mines to meet our nation's needs. The playing field should be leveled and mining companies should be permitted to fully expense such costs.
- As currently structured, the 10 percent <u>depletion allowance</u> for coal was reduced by 15 percent as part of an omnibus tax bill in 1986. The reduction should be repealed. Separately, the current 50 percent net income limitation per property on use of the depletion allowance should be eliminated or reduced as it was earlier for the oil and gas industry, thus leveling the playing field for capital investments.

RELIABLE, TIMELY AND COMPLETE ENERGY DATA
A REQUIREMENT FOR SOUND PUBLIC POLICY

**PRINCIPLE:** Data on energy production and consumption, available on a timely basis and that is complete, accurate and reliable is necessary to support sound decisions by both the government and the private sector.

**DESCRIPTION**: Development and implementation of sound energy policy requires that accurate, complete and timely data on energy production and consumption be made available to government policy makers and to the public. The Department of Energy's independent Energy Information Administration (EIA) is responsible for the collection, reporting and dissemination of data on all energy sources: petroleum, natural gas, uranium, renewables, electric generators and coal. Data on production, use, prices, stockpiles, environmental performance in terms of quality and emissions, and international trade are among the valuable data series for which EIA is responsible.

The information is used by Congress, federal, state and local governments, business and industry, educational institutions and the general public in a number of areas. One of the most important is analysis of the effects of policy proposals on energy supply, demand and price. Another use is for forecasting and this data provide the basis for EIA's own energy supply demand forecasts upon which the Administration relies when making energy policy decisions. Yet another use for this important data is determining the current state of the energy picture throughout the nation – for example, will heating oil stocks be sufficient for the winter season, will gasoline stocks carry through the summer, will electric generating capacity be enough to meet immediate demands, do utilities have coal stocks to carry them through a peak generating period, and so on. What are the levels of emissions of $SO_2$, $NO_x$, or $CO_2$? Timely, accurate and complete data can answer these questions and more and importantly allow a more informed public policy debate.

**STATUS**: The Energy Information Administration collects and publishes various data series on a weekly, monthly and annual basis. The Federal Regulatory Commission (FERC) collects data on the electric utility sector that in turn is complied and published by the EIA. The data on cost and quality of fuels delivered to utilities is collected on FERC "Form 423."

**KEY ISSUES**: Coal and electric utility data are no longer available on a timely basis nor are they accurate or complete. Data on coal production, employment, distribution and price (published on an annual basis) is more than ONE YEAR LATE. Data is not available at this point for even 1999. To compare – annual 1999 data on the petroleum industry was available in June 2000 and annual 1999 data on the natural gas industry was published in October 2000. Coal data has been treated as the "step-child" at the EIA and resources to collect and publish this data have been drastically reduced.

There is a different information issue affecting the electric generating sector. FERC does not have the authority to collect information from the non-utility generators (on Form 423) and as more of the industry becomes non-regulated, data on generation, fuel use and fuel purchases, inventories, etc. are increasingly incomplete. Additionally, OMB has been slow in acting on approval of the extension of authority to collect these data. As a result much of the data series required for sound energy policy decisions in the electric sector is simply not available. Not only is the federal government ignorant of coal inventories at power plants, for example, it does not have complete data on fuel prices and consumption.

**RECOMMENDATION**: Increase resources for collection and reporting coal data and take immediate steps to improve the timeliness of the information. Continue to authorize FERC collection of utility FORM 423 data and extend the information reporting requirements to the entire generating sector.

## URANIUM

- Changes to NRC Fee Structure
- Uses of the National Strategic Uranium Reserve
- Limitations on Sales of Government Uranium Stockpiles
- Domestic Nuclear Fuel Cycle Short Term Mitigation
- Extend Dates of USEC Privatization Act
- Domestic Uranium Research and Development
- Uranium Product Tax Credit

## CHANGES TO NRC FEE STRUCTURE

PRINCIPLE: Support for the domestic uranium recovery industry is essential for both energy and national security reasons. Legislation is necessary to eliminate fees for NRC uranium recovery.

BACKGROUND: NMA has consistently recommended changes to the Nuclear Regulatory Commission's (NRC) fee structure due to its impact on the domestic uranium recovery industry. There are serious inequities caused by the Omnibus Budget Reconciliation Act of 1990 (OBRA) mandate that NRC recover approximately 100 percent of its budget each year. In light of the current circumstances facing the uranium recovery industry, with the price of uranium hovering around $8/lb, the fees the uranium recovery licensees pay to NRC can be determinative of whether a company continues to produce uranium or instead proceeds to closure. These fees can also impact the amount companies can dedicate to reclamation.

DESCRIPTION: NRC's uranium recovery licensees pay an annual fee as well as an hourly fee for professional staff time. Unfortunately, with both types of fees, there is often no reasonable relationship between the cost to uranium recovery licensees of NRC's regulatory oversight program and the benefit derived from such services. The annual fee includes costs for activities not attributable to any existing NRC licensee or class of licensee such as international activities, Agreement State oversight, and licensing and inspection activities associated with other Federal agencies. This problem of the lack of reasonable relationship between annual fees and services rendered by NRC is exacerbated as more states become Agreement States, leaving fewer NRC licensees to bear an even greater share of the burden. Recent increases in NRC fees have resulted not from increases in the amount to be recovered but rather due mostly to more states becoming Agreement States. As more states become Agreement States and more sites are decommissioned, fewer NRC licensees bear an even greater share of the burden. Under this scenario, the last licensee could end up having to pay for the entire program.

The fees paid for professional staff time also often bear no relationship to services provided by NRC. Recent regulatory changes have required licensees to pay the full cost for all time accrued by the project manager assigned to their sites. In reviewing the NRC directives on such cost recovery, it seems virtually no activities the project manager engages in are excluded from cost recovery. Thus, licensees would not only pay for actual time the project manager spends on a their site but would also pay for other activities that have nothing to do with the licensees' sites, including support to other offices, support to other agencies, and international activities.

At a time when the domestic uranium industry is facing hardship due to low uranium prices, continued imports from the former Soviet Union and increased regulatory burdens, increased NRC fees are dealing a crippling blow to the domestic industry.

RECOMMENDATION: The Administration should support legislation that eliminates fees for NRC uranium recovery licensees until such time when the spot price of uranium ($U_3O_8$) has exceeded $14/pound (escalated) for one year.

## USES OF THE NATIONAL STRATEGIC URANIUM RESERVE

**PRINCIPLE:** Support for the domestic uranium recovery industry is essential for both energy and national security reasons. The Administration should support removal of federal uranium stockpiles from commercial markets.

**BACKGROUND:** Immediately prior to the privatization of United States Enrichment Corporation (USEC), USEC's offering documents established the transfer of in excess of 70 million pounds of Department of Energy (DOE) uranium and uranium equivalents to USEC. These massive transfers had not been anticipated by the domestic mining and conversion sectors of the nuclear fuel industry.

**DESCRIPTION:** In order to mitigate against the material adverse impact DOE's transfers had on these industries, DOE agreed not to sell or transfer additional uranium or uranium equivalents for a ten year period. The proposed amendment would codify the DOE action and extend the time of the stockpile requirements. Taking the remaining federal uranium stockpiles out of circulation would mitigate against the material adverse impacts previous sales and transfers have created, thereby reducing government fostered damage.

**RECOMMENDATION:** Amend 42 U.S.C. 2296b-1 National Strategic Uranium Reserve to read:

There is hereby established the National Strategic Uranium Reserve under the direction and control of the Secretary. The Reserve shall consist of natural uranium and uranium equivalents contained in stockpiles or inventories currently held by the United States for defense purposes all natural uranium and uranium equivalents acquired or obtained by the United States in the future, <u>and all natural uranium and uranium equivalents of Russian origin previously purchased or to be purchased in the future by the United States government pursuant to the Russian HEU Agreement</u>. Effective <u>on the date of enactment of this amendment</u> and for a period of <u>ten</u> years thereafter, use of the Reserve shall be restricted to military purposes and government research. Use of the Department of Energy's stockpile of enrichment tails existing on <u>the date of enactment of this amendment</u>, shall be restricted to military purposes or <u>to being processed as an alternate feed material by the domestic uranium recovery industry</u> for ten years thereafter.

## DOMESTIC NUCLEAR FUEL CYCLE SHORT TERM MITIGATION

PRINCIPLE: Support for the domestic uranium producers is essential for both energy and national security reasons. The Secretary of Energy should be authorized to purchase the USEC's uncommitted inventory of natural uranium.

BACKGROUND: The Department of Energy was required to transfer certain quantities of natural uranium and uranium equivalents to USEC as part of the privatization process. (*See* 42 U.S.C. 2297 h-10.) The sale of this material by USEC was restricted to no more than 4 million pounds per year to reduce the impact of this material on domestic producers and uranium equivalents produced pursuant to the Russian HEU Agreement. The Department made additional liabilities in lieu of cash payments to USEC owed due to liabilities remaining with the Department as a result of the Privatization Act. USEC sold this material into the commercial marketplace in addition to the amounts specifically authorized by congress in the Privatization Act.

DESCRIPTION: USEC's sales of restricted and non-restricted uranium derived from governmental stockpiles has damaged uranium producers resulting in a drop in the spot market price from $16.15 per pound at the time of privatization to an historic low of $7.10 in Dec. 2000.

RECOMMENDATION 1: Legislation on Domestic Nuclear Fuel Cycle Short Term Mitigation should be enacted to address the following. ( Recommendation 2, an alternative to Recommendation 1 is discussed below.)

### Section 1. In General.

Recent sales and transfers of government uranium inventories related to the Privatization of USEC and ramifications arising from the implementation of the Russian HEU Agreement have caused a material adverse impact on the mining, conversion and enrichment components of the *domestic nuclear fuel industry*.

### Section 2. Purchase of USEC's Uncommitted Uranium Inventory.

The Secretary is authorized to purchase USEC's uncommitted inventory of natural uranium and uranium equivalents of up to __________ pounds.

(a) These purchases shall be at the current spot market price as established by the Secretary or the price obtained by the Secretary when the natural uranium or uranium equivalent was transferred to USEC during the privatization of the United States Enrichment Corporation, whichever is higher.

### Section 3. Use of Purchased Uranium.

The natural uranium and uranium equivalents purchased under this section shall be placed in the National Strategic Uranium Reserve.

### Section 4. Authorization and Funding.

(a) In General
There is authorized to be appropriated $__________ to carry out this part.

(b) Source
Funds described in subsection (a) of this section shall be provided from:

**RECOMMENDATION 2**: As an alternative to recommendation 1, legislation could be passed that only requires the repurchase of certain contaminated materials from USEC by DOE as outlined below.

Amend 42 U.S.C. 2297-h – 10(C) USEC Privatization Act to read as follows:

**New Subsection (3)** Certain transfers from the Department made pursuant to this section and otherwise were contaminated by *technetium* existing in the material containers. The Secretary is authorized to purchase this material from USEC.

(A) The Secretary's purchases shall be at the current spot market price as established by the Secretary or the price determined by the Secretary when the natural uranium or uranium equivalent was transferred to USEC during the privatization of the United States Enrichment Corporation, whichever is lower.

(B) In the event the material purchased by the Secretary can be decontaminated or available for sale to commercial nuclear reactors, it shall be placed in the National Strategic Uranium Reserve.

(C)Authorization and Funding.

(i) In General – There is authorized to be appropriated __________ to carry out this part.

(ii) Source – Funds described in subsection (a) of this section shall be provided from ________________________.

## LIMITATIONS ON SALES OF GOVERNMENT URANIUM STOCKPILES

**BACKGROUND**: In order to mitigate against the material adverse impact DOE's transfers to USEC had on the domestic uranium recovery and conversion industries, DOE agreed not to sell or transfer additional uranium or uranium equivalents for a ten year period. Taking the remaining federal uranium stockpiles out of circulation would mitigate against the material adverse impacts previous sales and transfers have created, thereby reducing government fostered damage.

**DESCRIPTION**: Action is needed to limit the sales of government uranium stockpiles once such uranium is released from the ten year restriction on government sales. This limitation will prevent government stockpiled uranium from entering the commercial market in such quantities as to disrupt the market thereby enhancing the value of government owned uranium.

**RECOMMENDATION**: Limit the sales of government uranium stockpiles to four million pounds per year, once such uranium is released from the ten year restriction on government sales by amending 42 U.S.C. 2297h-10(d) Inventory Sales as follows.

(d) Inventory sales.

Subject to the restrictions required under Section 2296b-1 of this title, the Secretary may, from time to time, sell up to four million pounds per year of natural and low-enriched uranium (including low-enriched uranium derived from highly enriched uranium) from the Department of Energy's stockpile.

(2) No sale or transfer of natural or low-enriched uranium shall be made unless:

(A) the President determines that the material is not necessary for national security needs,

(B) the Secretary determines that the sale of the material will not have an adverse material impact on the domestic uranium mining, processing, conversion, or enrichment industry, taking into account the sales of uranium under the Russian HEU Agreement and the Suspension Agreement, and

(C) the price paid to the Secretary will not be less than the fair market value of the material.