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BEFORE THE
SUBCOMMITTEE ON FOSSIL AND SYNTHETIC FUELS
OF THE
COMMITTEE ON ENERGY AND COMMERCE
AND THE
SUBCOMMITTEE ON ENERGY AND THE ENVIRONMENT
OF THE
COMMITTEE ON INTERIOR AND INSULAR AFFAIRS

HOUSE OF REPRESENTATIVES

PREPARED STATEMENT
OF
JOHN G. MCMILLIAN
CHAIRMAN, BOARD OF PARTNERS
ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY

OCTOBER 20, 1981

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Prepared Statement

of

John G. McMillian
Chairman, Board of Partners
Alaskan Northwest Natural Gas Transportation Company

Mr. Chairman, I am John G. McMillian, Chairman and Chief Executive Officer of Northwest Energy Company and Chairman of the Board of Partners of Alaskan Northwest Natural Gas Transportation Company, the consortium of natural gas companies selected to design, construct, and operate the Alaskan segment of the Alaska Natural Gas Transportation System.

We are very pleased to appear here today to support the waiver of law proposed by the President. The Alaskan Northwest partnership, its Canadian counterpart, Foothills Pipe Lines (Yukon) Ltd., the three principal North Slope gas producers, Arco, Exxon, and Sohio, the project's financial advisors, both here and in Canada, and the lenders who are expected to provide a significant portion of project debt, have reached a critical stage with respect to completion of the ANGTS. Many hurdles, regulatory and otherwise, have been successfully surmounted. Over one-third of the total pipeline mileage is either complete or currently under construction. However, one significant hurdle remains -- final development of a private sector financing plan which will enable the remaining portions of the ANGTS to be constructed. The waiver you are considering is essential to development of a financing plan. Without the waiver, the ANGTS cannot be completed by private industry alone. If the ANGTS is not completed, consumers in this country would be denied access to over 13 percent of our nation's proven domestic gas reserves, and our country would be forced to maintain a greater dependency on vulnerable and insecure foreign energy sources.

Those who have become involved with this project following the discovery of the Prudhoe Bay field in 1968 are firmly committed to completion of this vital transportation link to the North Slope. This group includes most of the largest gas transmission companies in this country and Canada; the North Slope oil and gas producers which have developed the Prudhoe Bay reserves and were instrumental in the construction of the facilities necessary to bring the North Slope oil to lower 48 markets; and, collectively, both our financial advisors and the prospective lenders who have arranged the financing for most, if not all, major energy projects during the last two decades, and who are expected to arrange for and contribute significant amounts of the debt necessary to assure completion of the ANGTS.

We believe the ANGTS can and must be completed, and we welcome the opportunity to testify on behalf of the waiver proposal. We believe these hearings will amply justify the need for the proposed waiver and the need for expeditious, positive action. The waiver proposed by the President is not the same as that requested by Alaskan Northwest in June of this year. However, the modifications which have been made are acceptable to Alaskan Northwest as the minimum necessary to attempt to develop a private financing plan that will assure completion of the project.

My testimony today will provide a summary of the procedural background of the project, the construction to date, the major regulatory approvals and milestones, current activities, the estimated capital costs, the marketability of Alaskan gas, the benefits of the project to the U.S., the financing parameters, the regulatory approvals that still must be obtained, and a discussion of the waiver transmitted by the President.

I. PROCEDURAL BACKGROUND

A. Selection Process

In 1968 the largest single discovery of oil and natural gas ever found on the continent of North America was made at Prudhoe Bay on the North Slope of Alaska. The Prudhoe Bay field contains over twenty-six trillion cubic feet of recoverable natural gas, or 13 percent of all proven domestic gas reserves. Potential gas reserves in Alaska have been estimated at over 100 Tcf.

In view of the significant demand for natural gas in this country, it was recognized by all involved in the natural gas industry that construction of an economical transportation system for bringing Alaskan natural gas to the lower 48 states was imperative. This recognition led to the filing with the Federal Power Commission, the predecessor to the Federal Energy Regulatory Commission, of applications to construct such a transportation system.

1. <u>FPC Proceedings</u>

Between 1974 and 1976 three separate and competing gas company consortia, including Alaskan Northwest's predecessor, Alcan Pipeline Company, applied to the Federal Power Commission for authority to build a system to transport Alaskan gas to the lower 48 states. The three competing transportation proposals were consolidated for hearing and decision at the FPC and a massive formal evidentiary proceeding to determine the best proposal was initiated. During the course of the three years of hearings over 45,000 pages of testimony and over 1000 exhibits were compiled on all aspects of the design, financing, construction, and operation of two different overland pipeline routes through Alaska and Canada and an alternative Alaskan pipeline/liquified natural gas tanker system. Detailed consideration was given to such matters as gas reserves and deliverability, construction schedules and techniques, financing and cost of service, tariffs, marketability, geotechnical concerns, and socio-economic impacts. Additionally, comprehensive environmental impact statements were prepared by both the FPC staff and the Department of Interior. The FPC staff statement concluded that the most environmentally acceptable pipeline route was along the Alcan highway corridor and followed the 1975 issuance of a report to Congress by the Secretary of Interior, which concluded that an overland transportation system through Alaska and Canada for the transportation of North Slope gas reserves, including the

Alcan highway corridor route, was economically and technologically feasible. */

2. ANGTA

While the FPC was holding these hearings, Congress, recognizing the potential for delay at the FPC and the urgent need for Alaskan gas, enacted the Alaska Natural Gas Transportation Act of 1976. The purposes of the ANGTA were to provide a means for making a sound decision with respect to the selection of an Alaska Natural Gas Transportation System and, once the selection had been made, to expedite its construction and initial operation by expediting agency decisions, limiting and expediting judicial review of such agency decisions, and providing a mechanism by which the President could propose and Congress could waive laws that applied to the gas transportation system if necessary to permit the expeditious construction and initial operation of the system.

The ANGTA provided a six-part procedural framework to expedite a final decision on and construction of an Alaska Natural Gas Transportation System: (1) a FPC recommendation to the President based upon the record developed during the two years of evidentiary hearings on the three competing applications and briefs and comments to the Commission; (2) comments to the President on the FPC's recommendation by Federal agencies and others; (3) a Presi-

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*/ U.S. Dept. of the Interior, Alaskan Natural Gas Transportation Systems: A Report to the Congress, Pursuant to Public Law No. 93-153 (1975).

dential decision on the best possible ANGTS; (4) Congressional consideration and approval by joint resolution of the President's decision; (5) expedited handling of all Federal authorizations necessary or related to the construction and initial operation of the approved ANGTS; and (6) waiver of provisions of law where necessary for the expeditious completion of the ANGTS.

3. <u>FPC Recommendation</u>

On May 1, 1977, the FPC recommended that the President select the system for transporting Alaskan natural gas from the two overland pipeline proposals across Canada to the lower 48 states. Each of these pipeline proposals, however, took a different route through both Alaska and Canada.

4. <u>Federal Agency Comments</u>

On July 1, 1977, comments by various Federal agencies were submitted to the President. Every important issue regarding every major element of the FPC's recommendation was exhaustively studied through this system of recommendation and comments.

- The Federal Energy Administration, predecessor to the Department of Energy, concluded that any of the proposed systems to transport Alaskan gas to the lower 48 would help ensure that natural gas shortages do not occur and would reduce our dependence on foreign energy resources. The FEA also concluded that net national economic benefits of an ANGTS would be substantially positive.
- The Department of the Treasury stated that an economically viable system to transport natural

gas from Alaska to the lower 48 states could be privately financed.

- The Office of Coastal Zone Management of the Department of Commerce found that the adverse effects on native communities and local lifestyles would be less with the Alaskan Northwest route than with the other two competing proposals.
- The Council on Environmental Quality concluded that the Alaskan Northwest proposal was "the most environmentally acceptable" of the three competing proposals.
- The Department of the Interior found that the Alaskan Northwest route best minimized the environmental impact in Alaska if proper mitigative actions were taken.
- The Department of State concluded that a viable option existed for the transportation of Alaskan natural gas across Canada.
- The Justice Department report found that antitrust considerations did not militate against selection of any of the proposed transportation systems and that competitive considerations did not indicate the selection of one transportation system proposal in preference to the others.
- The Department of Transportation concluded that "with regard to pipelines, their continuity of service is by

far the best of any mode of transportation in the United States and we believe the Canadian experience is comparable." DOT also concluded that there was a "significant efficiency advantage to an all-pipeline system."

- A report by the Department of the Interior and the Department of Transportation found that the Alaskan Northwest proposal had the earliest expected delivery date and the least total cost.
- The Department of Defense found that a system to transport gas from Alaska to the continental United States was necessary to national security since it would enable the United States to reduce oil imports.

5. Canadian National Energy Board Selection of Alaskan Northwest Route

Following extensive hearings and deliberations, the Canadian National Energy Board on July 4, 1977 unanimously recommended certification of the Canadian portion of the route proposed by Alaskan Northwest's predecessor, Alcan, with several modifications. The NEB's decision was premised, in part, upon the environmental unacceptability of alternative routes.

Specifically, the NEB recommended certification of a Canadian segment consisting of approximately 2000 miles of pipeline to begin at the Alaska-Yukon border and proceed to a point near the James River, Alberta, where the pipeline would divide into the Eastern and Western Legs and proceed to delivery points near Monchy, Saskatchewan and Kingsgate, British Columbia. This route was sponsored by Foothills Pipe Lines (Yukon) Ltd., which is owned equally by NOVA, an Alberta corporation, (formally The Alberta Gas Trunkline Company Limited) and Westcoast Transmission Company Limited.

6. Transit Pipeline Treaty

On August 3, 1977, the U.S. Senate ratified a treaty between the United States and Canada concerning "transit pipelines." This Transit Pipeline Treaty applies to the transmission by pipeline through one country of hydrocarbons not originating in that country for delivery in the other country.

The treaty prohibits authorities in either country from taking any measures which would impede, divert, redirect, or interfere with the transmission of hydrocarbons in transit. It also provides that each country will facilitate the expeditious issuance of permits, licenses, and other authorizations needed for the import or export through its territory of hydrocarbons through a transit pipeline.

The treaty mandates that public authorities in both countries not impose fees, duties, taxes, or other monetary charges on a transit pipeline not placed on similar pipelines not transiting the national border.

7. Agreement on Principles

On September 20, 1977, the United States and Canada signed an "Agreement on Principles Applicable to a Northern Natural Gas Pipeline" which established the terms and conditions by which the two countries would cooperate on a joint gas pipeline system for the transportation of gas from Alaska and northern Canada. This Agreement provides for:

- prompt governmental approval of necessary permits, licenses and certificates;
- nondiscriminatory charges assessed in a just and reasonable manner;
- expeditious and efficient construction;
- sufficient capacity to meet the needs of U.S. and Canadian shippers;
- private financing and a variable rate of return;
- nondiscriminatory taxation;
- procurement practices on "generally competitive" terms;
- coordination and consulation between the governments and their respective regulatory authorities (the FERC and the NEB); and,
- each government to take measures necessary to facilitate timely construction, consistent with their respective regulatory requirements, and to seek all required legislative authority to facilitate expeditious construction and remove any causes of delay.

8. President's 1977 Decision

On September 22, 1977, the President issued his Decision and Report to Congress on the Alaska Natural Gas Transportation System selecting the Alaskan Northwest pipeline proposal and route as the most efficient, economic and cost effective means to bring Alaska gas to the lower 48 states. The Decision designated Alaskan

Northwest's predecessor, Alcan, to construct and operate the 745 mile pipeline segment commencing at the outlet of the Prudhoe Bay gas conditioning plant and extending to the Alaska-Yukon border; Northern Border Pipeline Company to construct and operate the U.S. Eastern Leg, consisting of approximately 1,130 miles of pipeline extending from Monchy, Saskatchewan to Ventura, Iowa for the transport of approximately 70 percent of the Prudhoe Bay gas to markets in the Midwestern, Eastern, and Southern portions of the United States; and Pacific Gas and Electric Company and its affiliate, Pacific Gas Transmission Company, to construct and operate the U.S. Western Leg, extending approximately 910 miles from Kingsgate, British Columbia to the San Francisco Bay area, for the transport of approximately 30 percent of the Prudhoe Bay gas to markets in the Western United States.

The President's Decision specifies certain terms and conditions that would apply to the ANGTS:

- Enforcement of the terms and conditions by a Federal Inspector;
- Approval or, in certain instances, review by the Federal Inspector of a comprehensive management plan, cost and schedule control techniques, final construction design, purchase procedures, labor management programs, quality assurance and control procedures, safety precautions, and environmental protections;
- Approval by the Federal Inspector of an affirmative action program for minority business enterprises;

- Use of a variable rate of return mechanism to provide incentives for project completion below budgeted costs;
- No tariff could be used which required payment from consumers prior to the completion and commissioning of the system; and
- Requirement that Alaskan gas producers have no equity, voting, or management position in the ANGTS.

The Decision also incorporated the complete text of the September 20, 1977 Agreement on Principles between the U.S. and Canadian governments.

9. Congressional Approval of Selection of Alaskan Northwest to Build the ANGTS

On November 2, 1977, Congress approved the President's Decision and the environmental impact statement prepared for the approved ANGTS. (H.J. Res. 621, Pub. L. No. 95-158) (Appendix A).

10. FERC Issuance of Conditional Certificates

Under Section 5(a)(2) of the ANGTA, the completion of the selection process in the U.S. required that the Commission issue certificates to those chosen to construct and operate the ANGTS. Accordingly, on December 16, 1977 the Commission issued conditional certificates to Alaskan Northwest's predecessor, Alcan, Northern Border Pipeline Company, and Pacific Gas Transmission Company for their respective segments of the ANGTS. */ In that order, the Commission identified several additional areas of

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*/ The segment to be constructed within California by Pacific Gas and Electric Company is subject to the jurisdiction of the California Public Utilities Commission.

inquiry that needed to be addressed before final certificates could be issued. The Commission appointed an Alaskan Delegate to conduct proceedings on these areas on its behalf and to make recommendations with respect to their resolution.

11. Northern Pipeline Act

On April 12, 1978, the Canadian Parliament enacted the Northern Pipeline Act, which ratified the July 4, 1977 decision of the Canadian National Energy Board certificating the Canadian segment of the ANGTS and approved the construction and operation of that segment of the ANGTS. This Act also established the Northern Pipeline Agency to facilitate planning and construction of the Canadian pipeline, to implement the terms and conditions of the Agreement on Principles, and to monitor and minimize the social, economic, and environmental effects of the construction and operation of the Canadian segment of the ANGTS.

B. Related Matters

1. Natural Gas Policy Act

On November 9, 1978, the pricing of natural gas was modified by enactment of the Natural Gas Policy Act. That Act established the wellhead price of Prudhoe Bay gas at $1.45 per MMBtu as of April 1977, subject to escalation for inflation; provided that price regulation of Prudhoe Bay gas will continue beyond January 1, 1985, when wellhead price regulation will end for certain other categories of gas; and allowed the delivered price of Alaskan gas to be rolled-in with the prices paid by U.S. pipelines for gas from other sources for resale to distribution companies, industrial customers, and other end users.

2. Office of the Federal Inspector

Congress included a provision in the ANGTA requiring the appointment of a Federal Inspector and authorizing him to take the following actions to facilitate government monitoring of the ANGTS: establish a joint surveillance and monitoring agreement with the State of Alaska; monitor compliance with applicable laws and the terms and conditions of any applicable certificate, right-of-way, permit, lease, or other Federal authorization; monitor actions taken by the sponsors to assure timely completion of construction schedules and the achievement of quality construction, cost control, safety, and environmental protection objectives; subpoena information necessary to carry out his responsibilities; keep the President and Congress currently informed on any significant departures from compliance; and issue quarterly reports to the President and the Congress.

As previously indicated, the President's 1977 Decision provided the Federal Inspector with certain additional specific duties and responsibilities including the following: approval of the ANGTS sponsors' overall management plans; approval of insurance, bonding, and pre-qualification requirements for contractors; approval of the design of any segment prior to construction; and approval of affirmative action plans.

In addition, the Federal Inspector must also review the methods for supplying equipment, repair facilities, and spare parts inventories to the execution contractors; collective bargaining agreements and labor relations procedures; quality assurance and control procedures; proposed cost and schedule control techniques; and all plans for implementation of specific environmental safeguards.

3. Reorganization Plan No. 1

In May 1979, Congress allowed the President's Reorganization Plan No. 1 of 1979 to take effect, which transferred to the Federal Inspector from various Federal agencies the responsibility to enforce the terms and conditions imposed by those agencies in the permits, rights-of-way, or other authorizations issued with respect to the ANGTS. This responsibility includes compliance or oversight activities reasonably related to the enforcement process. In addition to enforcement functions, Reorganization Plan No. 1 charged the Federal Inspector with the responsibility to coordinate the expeditious discharge of permitting activities by all Federal agencies and to ensure their compliance with Section 9 of the ANGTA, which requires expeditious agency action on all ANGTS-related matters. The purpose of this provision was to establish a "one window" approach to the governmental approval process.

Finally, the Federal Inspector is acting in the role of the "senior official" contemplated in the Agreement on Principles with Canada, whose obligation is to consult with Canada concerning implementation of the principles relating to the construction and operation of the ANGTS.

II. ANGTS CONSTRUCTION TO DATE

Construction of approximately 1,000 miles of the ANGTS in the lower 48 states and approximately 500 miles in southern Canada, or 30 percent of the total pipeline mileage, is now either complete or underway. This portion of the system is being "pre-built" to permit the U.S. to import an additional 1.215 billion cubic feet per day of Canadian gas for transportation through these "pre-built" facilities, pending completion of the entire ANGTS and transportation of Alaskan gas.

Following a hearing process on the pre-build facilities lasting one and one-half years, including formal evidentiary hearings, the Commission in 1980 authorized Northwest Alaskan to import for transportation through the Western Leg pre-built facilities of the ANGTS up to 300,000 Mcf of natural gas per day purchased from Pan-Alberta Gas, Ltd. for delivery to southern California markets. Imports through these facilities commenced October 1, 1981.

In 1980 the Commission also authorized Northwest Alaskan and others to import through the Eastern Leg pre-built facilities of the ANGTS up to an average of 975,000 Mcf of natural gas per day purchased from Pan-Alberta for delivery to Eastern, Midwestern, and Southern markets. Imports through these facilities will commence in the fall of 1982.

The estimated cost of the pre-build facilities is approximately $1.7 billion in 1980 dollars. Construction to date on the pre-build facilities has been on schedule and modestly under budget.

The related authorizations of the National Energy Board of Canada, both for the export of Canadian gas through the "pre-built" facilities and the construction of such facilities in Canada, were issued only after assurances were provided by both the Congress and the President that the ANGTS remained in the national interest and should be completed expeditiously and that steps would be taken in the U.S. to permit the Canadian sponsors to commence billing for the Canadian segment when it was completed and ready to operate.

Specifically, on July 18, 1980 President Carter sent a letter to Prime Minister Trudeau of Canada stating that the United States ". . . stands ready to take appropriate additional steps necessary for completion of the ANGTS." (Appendix B). With respect to the financing of the Canadian portion of the ANGTS, President Carter stated as follows:

> . . . the reasonable concern of Canadian project sponsors that they be assured recovery of their investment in a timely manner if, once project construction is commenced, they proceed in good faith with completion of the Canadian portions of the project and the Alaskan segment is delayed. In this respect, they have asked that they be given confidence that they will be able to recover their cost from U.S. shippers once Canadian regulatory certification that the entire pipeline in Canada is prepared to commence service is secured.

and concluded that:

> . . . I accept the view of your government that such assurances are materially important to insure the financing of the Canadian portion of the system.

> . . . I would be prepared at the appropriate time to initiate action before the U.S. Congress to remove any impediment as may exist under present law to providing that desired confidence for the Canadian portion of the line.

In July 1980, Congress passed a concurrent resolution (S.Con. Res. 104) expressing the ". . .sense of the Congress that the System remains an essential part of securing this Nation's energy future and, as such, enjoys the highest level of congressional support for its expeditious construction and completion by the end of 1985." (Appendix C). This Congressional expression of support provided the Canadian government with a critical assurance that construction of the entire ANGTS remained a U.S. priority. Support for the ANGTS by both the President and the Congress was necessary before the Canadian government would proceed to authorize the export of Canadian gas in support of the pre-built portions of the ANGTS.

III. OTHER MAJOR REGULATORY APPROVALS ALREADY SECURED AND SIGNIFICANT MILESTONES

Progress has also been made on the non-pre-build portions of the ANGTS in the four years since issuance of the President's 1977 Decision and Congressional ratification of that Decision. Numerous regulatory approvals required -- both in the U.S. and Canada -- have been issued and other significant milestones have been achieved.

A. Partnership Agreement

The Alaskan Northwest Natural Gas Transportation Company partnership was formed effective January 31, 1978 by subsidiaries of six major natural gas companies to own the Alaskan pipeline segment of the ANGTS. Since then, four other major natural gas companies, through their subsidiaries, have joined the partnership, bringing the membership to a total of ten companies. Thus, the Alaskan Northwest partnership is presently composed of affiliates of the following U.S. and Canadian natural gas companies: Northwest Alaskan Pipeline Company - an affiliate of Northwest Pipeline Corporation and subsidiary of Northwest Energy Company; American Natural Alaskan Company - an affiliate of Michigan Wisconsin Pipe Line Company and a subsidiary of American Natural Resources Company; Calaska Energy Company - an affiliate of Pacific Gas Transmission Company and a subsidiary of Pacific Gas and Electric Company; Northern Arctic Gas Company - a subsidiary of InterNorth Inc., of which Northern Natural Gas Company is a division; Pacific Interstate Transmission Company (Arctic), an affiliate of Pacific Interstate Transmission Company and a subsidiary of Pacific Lighting Corporation; Pan Alaskan Gas Company - an affiliate of Panhandle Eastern Pipe Line Company, a subsidiary of Panhandle Eastern Corporation; Columbia Alaskan Gas Transmission Corporation - an affiliate of Columbia Gas Transmission Corporation, a subsidiary of The Columbia Gas System, Inc.; Tetco Four, Inc., - an affiliate of Transwestern Pipeline Company and Texas Eastern Transmission Corporation, a subsidiary of Texas Eastern Corporation; Trans-Canada Pipe Line Alaska Ltd. - an affiliate of TransCanada PipeLines Limited; and United Alaska Fuels Corp. - an affiliate of United Gas Pipe Line Company, a subsidiary of United Energy Resources, Inc.

The combined assets of these partners and their parents and affiliates exceeds $40 billion. Their total 1980 gas sales were in excess of 7.8 Tcf, or 56 percent of all gas sales by major interstate pipelines in that year. As illustrated in the map attached as Appendix D, the affiliates of the partners transport gas ultimately distributed in 48 of the 50 states.

Alaskan Northwest, as a General Partnership under the Uniform Partnership Act of the State of New York, will finance, own, construct, and operate the Alaskan facilities that are part of the ANGTS.

Northwest Alaskan Pipeline Company has been designated operating partner by the partnership agreement with responsibilities for day-to-day activities necessary to plan, design, construct, and operate the Alaskan facilities.

The partnership is the successor in interest to Alcan Pipeline Company under ANGTA, the President's Decision, and related Federal Power Commission and Federal Energy Regulatory Commission orders, pursuant to a Commission order of June 30, 1978, which transferred the conditional certificate of public convenience and necessity from the original certificate holder, Alcan, to the Alaskan Northwest partnership. This order also found the terms and conditions of the partnership agreement consistent with the requirements of ANGTA and the President's Decision.

B. Incentive Rate of Return

In a normal pipeline certificate application, the FERC reviews the applicant's estimate of construction costs in determining whether to issue a certificate of public convenience and necessity authorizing the construction and operation of the proposed pipeline. Once a certificate is issued and construction completed, all costs are reviewed for prudency, and all prudent costs are then included in the pipeline's rate base. The pipeline earns its approved just and reasonable return on the investment deemed prudent, even if actual costs exceed the estimate approved by the Commission at the time of certification.

The President's Decision imposed a requirement in addition to the Commission's normal certification cost review and prudency determination -- establishment of a variable rate of return mechanism which would increase the ANGTS sponsors' allowable return for cost underruns or decrease their return for cost overruns. Unlike the normal pipeline certification process, under the President's guidelines the ANGTS sponsors would be penalized for cost overruns even if such additional costs were found prudent.

Pursuant to the mandate of the President's Decision to devise a variable rate of return mechanism, the FERC on May 8, 1978 commenced a rulemaking which culminated in the issuance of its Orders 31 and 31-B on June 8 and September 6, 1979. These orders established an incentive rate of return (IROR) mechanism applicable to the Alaskan Northwest and Northern Border segments governing the rate of return that the ANGTS sponsors of those segments may earn on project investment.

The basic elements of the Commission-approved IROR mechanism are the Cost Performance Ratio and an associated IROR schedule of rates of return. The Cost Performance Ratio is the ratio of Actual Capital Costs (derived from the final construction costs) to the Projected Capital Costs (derived from the FERC-approved Certification Cost Estimate, as modified by the Federal Inspector-approved Final Design Cost Estimate, which is the total estimated cost at the start of construction and any approved scope changes during construction). The Cost Performance Ratio is intended to measure how well project management has succeeded in controlling the costs of the project. An IROR schedule specifies an allowed rate of return for each possible Cost Performance Ratio. The lower the value of the Cost Performance Ratio the higher will be the allowed rate of return, and vice versa. The lowest return is referred to as the Marginal Rate of Return, which is 8 percent. Thus, the Alaskan Northwest partnership will earn only 8 percent return for each equity dollar of cost overrun above the government-established target cost estimate. Given today's interest rates, the 8 percent return is truly a penalty rate.

The proceeding to determine the initial target cost estimate to be used in the later establishment of the sponsors' actual equity return is now pending at FERC.

C. <u>FERC Approved Gas Tariffs</u>

In addition to the IROR mechanism, Commission Orders 31 and 31-B also approved Alaskan Northwest's and Northern Border's pro forma tariffs for the transportation of natural gas on behalf of the shippers of Alaskan gas. These approved tariffs specify the services to be performed, the method for computing the amount of payment for those services, and all related terms and conditions.

The tariffs are based on the concept of a monthly "cost-of-service" charge, which provides that the total charges to all shippers will equal the actual costs to Alaskan Northwest and Northern Border of performing the transportation service, including an allowed return on invested capital. Pursuant to the tariffs, service agreements will be entered into by Alaskan Northwest and each individual shipper and by Northern Border and the Eastern Leg shippers. */

The following key provisions are included in the Alaskan Northwest and Northern Border tariffs approved by the FERC:

1. Billing Commencement Date and Minimum Bill

The FERC ruled that billing commencement for Alaskan gas can begin when all ANGTS pipeline segments -- the Alaskan pipeline segment, the Canadian pipeline segment, the U.S. Eastern Leg, and the U.S. Western Leg -- are completed, tested, and proved capable of operating. Thus, under the existing approved tariffs, billing can in effect commence before the gas conditioning facility is operational and/or before gas is available for transport. The rate to be charged upon completion and commissioning is limited to a "Minimum Bill" which permits recovery of (i) actual operating and maintenance expenses, (ii) current taxes, and (iii) debt

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*/ Western Leg shippers will enter into service agreements with PGT and PG&E. Alaskan gas tariffs for the Western Leg were not considered in Commission Orders 31 and 31-B, because the Western Leg is not subject to the IROR mechanism.

service including interest and scheduled debt retirement. This level of reduced billing (which does not include a return on, or of, equity investment) would continue until gas is tendered for shipment and transportation service commences.

2. <u>Interim Rate</u>

The FERC established an Interim Rate to commence with the initial delivery of gas through the system, which terminates on the earlier of the first year of operation or upon the attainment of design capacity throughput, whichever occurs earliest. The level of the Interim Rate is to be computed on the basis of the projected cost of service for the first 12 months of operation divided by the system design capacity throughput. The Interim Rate is to be no lower than the Minimum Bill then applicable.

3. <u>Service Interruption</u>

The tariff as approved by the FERC provided for three categories of service interruption:

i) <u>More than a 10 percent reduction in service</u> -- If Alaskan Northwest or Northern Border is unable to accept and transport at least 90 percent of the Alaskan gas tendered to it for any one month, charges to shippers would be reduced for return <u>on</u> equity and associated income taxes proportional to the percentage of volumes tendered but not transported.

ii) <u>Less than a 10 percent reduction in service</u> -- If Alaskan Northwest or Northern Border is able to transport more than 90 percent of the gas tendered by the shippers, there would be no reduction in charges to shippers.

iii) Extended total service interruption -- In the event of a total cessation of service for 30 consecutive days, the segment responsible for the service interruption would be permitted to continue to collect that portion of its charges attributable to equity costs (*i.e.*, that portion of depreciation expense not necessary for debt service and associated taxes), subject to refund pending determination of the cause of the interruption. However, under no circumstances would debt service ever be impaired.

D. Pipe Size and Pressure

Following application by Alaskan Northwest, a report by the Commission's Alaskan Delegate and comments by all interested parties, the Commission on August 6 and October 15, 1979 issued orders establishing the design specifications and initial capacity of the Alaskan segment of the ANGTS. These specifications included the pipe diameter and maximum operating pressure of the pipeline, which largely determine the capacity throughput of the line and the ability of the gas stream to carry natural gas liquids. Based on its review of the report by its Alaskan Delegate and the comments of the parties, the Commission determined that the Alaskan pipeline segment of the ANGTS would be built with 48-inch diameter pipe, have a maximum operating pressure of 1260 psig, and have compressor station size and spacing for an initial capacity of 2.0 to 2.4 billion cubic feet per day but capable of expansion to an average daily volume of 3.2 billion cubic feet per day. The FERC orders were affirmed on appeal on January 3, 1980 in Earth Resources Company of Alaska v. FERC, 617 F.2d 775 (D.C. Cir.).

E. Federal Right-of-Way in Alaska

Since the majority of the lands traversed by the Alaska pipeline segment of the ANGTS is controlled by the Federal government, it was necessary to obtain a pipeline right-of-way from the Department of Interior. On August 19, 1980, the Department of Interior stated its intent to grant a right-of-way to Alaskan Northwest to cross Federal lands in the State of Alaska. Pursuant to Section 28(w)(2) of the Mineral Leasing Act of 1920, the Department of Interior requested that Congress waive the prescribed 60-day review period, which was done. On December 1, 1980 the right-of-way grant was formally issued by the Department of Interior.

The right-of-way contains numerous terms and conditions with which Alaskan Northwest must comply. In addition to extensive environmental restrictions, two of the most important stipulations are the requirement that Alaskan Northwest assist in the training of Alaskan natives for employment on the project and the requirement that the ANGTS be separated from the existing Alyeska oil line by 200 feet. The Department of Interior had previously required that the sponsors of the Alaska pipeline segment enter into a mutual indemnification agreement with the owners of the

Alyeska oil pipeline for damages that may occur on the respective rights-of-way. Such agreement was executed on November 26, 1980.

F. Environmental Terms and Conditions

On February 26, 1980, the Commission incorporated two general conditions into the conditional certificates of public convenience and necessity which had been issued to the ANGTS sponsors by Commission order of December 16, 1977. These conditions are applicable to all lands crossed by the pipeline, regardless of ownership. The first condition requires compliance with the Commission's regulations that establish guidelines for the location, clearing, and maintenance of pipeline rights-of-way and sites for related facilities. The second condition provides for the issuance of stopwork orders by the Federal Inspector.

G. Equal Employment Opportunity/Minority Business Enterprise

On May 7, 1980 the Department of Interior, pursuant to Section 17 of ANGTA and Condition I-11 of the President's Decision, promulgated final rules to ensure that no person will be excluded from participating in any activity connected with the construction and operation of the ANGTS on the basis of race, creed, color, national origin, or sex. On May 8, 1980 the Commission issued an order attaching the above-referenced rules to the ANGTS sponsors' conditional certificates of public convenience and necessity.

H. Delegations to and Approvals by the Federal Inspector

On March 31, 1980 the Commission delegated to the Federal Inspector the authority to attach terms and conditions to the certificates of public convenience and necessity issued to the ANGTS sponsors to implement the requirements of the National Historic Preservation Act of 1966 and the Preservation of Historical and Archaeological Data Act Amendments of 1974.

In May 1980 Alaskan Northwest filed its overall management plan with the Federal Inspector, in accordance with Condition I-1 of the President's Decision. This plan was approved in principle by letter dated June 6, 1980 subject to submission of supplemental support of specific details of that plan.

By order issued December 19, 1980 the Commission delegated to the Federal Inspector the responsibility to determine the prudency of expenditures to construct the ANGTS.

On August 13, 1981, the Federal Inspector approved Alaskan Northwest's Affirmative Action Plan, which covers both equal employment opportunity and minority and female business goals and timetables.

I. Cooperative Agreement Among Alaskan Northwest, the Principal North Slope Producers, and the State of Alaska

After extensive negotiations, Alaskan Northwest and the major Prudhoe Bay gas producers -- Arco, Exxon, and Sohio -- entered into a Cooperative Agreement in June 1980 relating to the design and engineering of the Alaskan gas pipeline and the related gas conditioning plant. This document was reviewed by the Department of Justice and the Department of Energy prior to its execution. The Alaskan Northwest partnership and the producers stated their joint intention to work together to expedite the design, engineering, and cost estimation of the Alaskan pipeline and gas conditioning facilities and to develop a financing plan in such a time and manner that all necessary government approvals could be obtained and facilities completed at the earliest practicable date. The Cooperative Agreement, to which the State of Alaska was also a signatory, became effective on June 20, 1980 and established a jointly funded, jointly managed Design and Engineering Board to continue the design, engineering, and construction planning of the Alaska pipeline segment and to begin the design and engineering of the gas conditioning plant necessary to prepare the gas for pipeline transmission.

Under the Cooperative Agreement, the producers agreed to contribute approximately $90 million to the design and engineering undertaking prior to further contributions by the Alaskan Northwest partnership. This contribution level was reached during January 1981. Thereafter, the Alaskan Northwest partnership and the producers have been contributing on a 50-50 basis toward design and engineering work for the Alaska gas pipeline and the conditioning plant. To date over $550 million has been spent in this effort alone.

The State of Alaska has thus far participated in monitoring the design and engineering effort as an observer. The State can, however, elect to participate actively in the financing and management of the design and engineering effort at any time.

IV. CURRENT ACTIVITIES

A. Alaskan Pipeline Segment

In 1978 Alaskan Northwest selected Fluor Engineers and Constructors, a subsidiary of Fluor Corporation, as its Project Management Contractor. Fluor was selected on the basis of its proven record as one of the world leaders in project management and arctic engineering and contracting.

Alaskan Northwest and Fluor have assembled a team of over 400 highly experienced cost estimators, cost engineers, design and pipeline engineers, and environmental and other experts representing every discipline necessary for estimating, designing, engineering, constructing, and controlling the cost of a project of the magnitude of the ANGTS. The companies working with Alaskan Northwest and Fluor in this effort include Gulf Interstate Engineering, Michael Baker, Jr., Inc., Northern Technical Services, Inc., and R&M Consultants, Inc. Also involved are execution contractors who participated in the construction of the Alyeska oil pipeline, as well as many other multi-billion dollar construction projects in Alaska and Canada, including Morrison-Knudsen, Reading & Bates Construction Company, a subsidiary of Reading & Bates Corporation, Peter Kiewit and Sons, Curran Houston Inc., a subsidiary of Sedco Inc., and Green Construction Company.

Collectively, Alaskan Northwest, Fluor, and these consultants have spent over three years and more than 1,000,000 workhours in the design and engineering of the Alaskan pipeline segment, including extensive, highly technical field programs to ensure the correct design, and over one year in preparing a detailed capital cost and schedule estimate for this segment. The final Alaskan pipeline design and engineering work is approximately 34 percent complete, and preconstruction field programs will be approximately 72 percent complete by the end of this year.

1. <u>Design and Field Programs</u>

The ANGTS will be designed and constructed as a chilled, high pressure, buried pipeline system utilizing traditional and well established techniques. Certain problems are encountered in the far north which require special attention due to the severe climate and unusual soil conditions. However, with the design and engineering work accomplished to date, no insurmountable technical problems have been identified. Hence, the remaining challenge is to determine the conditions to be encountered and to develop the most cost-effective design and construction mode to complete the system in a safe and cost-effective manner.

During the development of the design, numerous engineering review sessions were held between Alaskan Northwest, Fluor, their consultants and leading engineers from several key Federal agencies -- the United States Geological Survey, the Corps of Engineers, and its Cold Regions Research and Engineering Laboratories.

These technical experts, along with engineering specialists from Alyeska, have provided an additional source of expertise which adds significantly to the project effort, especially in the critical areas of frost heave design and geotechnical/geothermal requirements.

An additional source of technical expertise comes from the producer and pipeline companies participating in the project. Engineering specialists in soil mechanics, geotechnical, and geothermal disciplines have been made available to Northwest Alaskan for special engineering assignments. The Foothills engineering group in Canada is another important source of expertise. The exchange of technical data with Foothills has been quite valuable. The Canadians have considerable experience in arctic engineering dating back to the early 1950s. Significant areas where the project is benefiting from Canadian participation is in frost heave, fracture control, and the development of new construction methods. Foothills has operated a frost heave test site facility near Calgary for several years and has just concluded an extensive full scale pipe burst testing program, part of which was carried out to Alaskan Northwest specifications in order to determine optimum fracture control design. Additionally, late last year Foothills initiated field testing of materials and construction methods at their Quill Creek facility in the Yukon. Aside from the testing of construction modes, this facility was designed to verify insulation systems and construction methods, including development of new equipment.

a. Frost Heave and Other Testing

Of all design requirements, the development of suitable methods for frost heave mitigation is probably the most demanding. Much of the soils in Alaska are characterized by permafrost. The pipeline will operate in a chilled state in Alaska and part of Canada to avoid damage to these soils from melting of the frost in the soil. However, the chilled pipeline must be designed to avoid or withstand frost heave. Frost heave is the phenomena where unusual stress may be placed on the pipeline causing potential movement or heaving due to growth of a frost bulb around the pipeline caused by the cold pipeline freezing water which has migrated to the pipeline from surrounding soil.

A full scale field testing installation, comprised of ten different modes or types of pipe sections, was completed at Fairbanks in the fall of 1979. The Fairbanks site was selected because the soil type prevalent in this area is considered by geotechnical specialists to be a worst case situation. The Fairbanks frost heave test site has been in operation since October 1979. The results to date have been most encouraging, with the magnitude of heave experienced being approximately one half of the amount predicted.

In recognition of the value of full scale testing, a decision was made in 1980 to install six additional frost heave test sites, which sites were selected for the purpose of providing the widest range of soil types and silt content attainable. Installation work at the six sites was completed in the first quarter of 1981, and operational start-up is in progress at all sites. Initial results from the first site to become fully operational are comparable to the data obtained from the Fairbanks installation.

A similar field testing approach is being utilized in other specialized engineering areas, e.g., the development of a suitable pipe insulation system, fracture arrest, and soil stability. The expertise needed to develop satisfactory methods for handling these requirements has been assembled by the project as a means of assuring that the most cost effective design is achieved.

b. Site Specific Requirements

Another important element of the project engineering effort involves site specific requirements. For example, almost one-third of the pipeline location in Alaska is either parallel and adjacent to the Alyeska oil pipeline or the State Haul Road, which connects central Alaska with Prudhoe Bay and the North Slope. To establish a suitable location in these areas the design must give adequate consideration to the adjacent structures.

In some cases, where problems exist due to terrain, cross-drainage, slope stability, or other external factors, the design must be modified. Quite often, the most cost effective solution is to change the gas pipeline alignment so that the problem can be completely avoided.

The necessary interaction between the Alaskan Northwest/Fluor project group, Alyeska, and State/Federal representatives can best be described with an example. The original pipeline alignment included over 60 crossings of the Alyeska oil pipeline system.

Because of the problems involved in several of these crossings, route studies were conducted and the number of crossings reduced to 23. Subsequent discussions with Alyeska engineers have resulted in resolving the design criteria for most of these crossings.

Detailed working sessions have been initiated with both Alyeska and the State for the purpose of resolving all matters pertaining to proximity of the oil pipeline, State Haul Road, and the gas pipeline. These working sessions will involve special engineering groups, comprised of Alaskan Northwest/Fluor engineering, environmental, and construction personnel and engineers and other disciplines from Alyeska and the State. Each working group will have specific tasks assigned and participation will be limited to those who have the knowledge and experience required to resolve specific engineering problems.

c. Environmental Concerns

Equally important, the development of the engineering design for the project includes direct participation by the Alaskan Northwest/Fluor environmental affairs group. Their representatives are working with project design engineers on a continuous basis to assure that environmental requirements are incorporated at an early stage into the development of the design. The early recognition of environmental requirements in the design process will provide a better basis for alleviating sensitive environmental concerns and for obtaining government approval of the basic design prior to the commencement of construction.

d. Alyeska Experience

The risk of cost overruns in the construction of the Alaskan ANGTS facilities has been lessened as a result of completion of the Alyeska oil pipeline. The following points are noted:

-- Both the similarities and differences of the two projects are such that the uncertainties, risks, and potential for cost increases to which the gas line will be exposed are considerably less than was the case for the oil line.

-- Today, much more is understood about the process of building a large diameter pipeline in Alaska -- from a technical point of view and with regard to management, government involvement, infrastructure, and the supply and demand for critical manpower and equipment resources.

-- Transporting chilled gas through permafrost is inherently easier than transporting heated oil in the arctic.

-- The oil line was a pioneer project, built across a tremendous expanse of land that had nothing in the way of support infrastructure, such as highways to the job site and communications systems. To a large extent, the gas line will take advantage of this existing infrastructure. Furthermore, the entire infrastructure in the State of Alaska is now significantly more supportive than what existed in 1971, and much improved technical, managerial, and construction capability exists in Alaska today.

2. Certification Cost Estimate

Simultaneous with the design and engineering of the Alaskan pipeline segment, the Alaskan Northwest/Fluor team has prepared a detailed, fifty-volume cost and schedule estimate for FERC review in accordance with the mandate of the President's Decision and FERC orders implementing the Decision. This estimate was filed with the FERC on July 1, 1980, as revised on October 27, 1980. The total estimate is comprised of a base engineering estimate of the cost of construction, a normal contingency allowance, plus an estimate of the possible cost impacts from abnormal events.

a. Estimate Highlights

The base engineering estimate includes the management, engineering, procurement, construction, testing, and start-up for the Alaskan pipeline segment of the ANGTS from the outlet of the gas conditioning plant at Prudhoe Bay, Alaska to the Canadian (Yukon) Border. The following are the highlights of major facilities.

-- Compressor Stations - Four stations containing one 25,000 horsepower compressor each and three with two such units. Each station will also have a refrigeration system to chill the gas.

-- Metering Stations - One station at Prudhoe Bay, which is combined with the plant's metering facilities, and one at the Yukon Border.

-- Operations and Maintenance Facilities - One leased facility at Fairbanks and three other facilities located at compressor stations.

-- Temporary Facilities - camps, airfields, warehousing, freight, and office space.

-- Communications and Supervisory Controls Systems - Utilizes existing and new facilities, land-based and satellite.

-- Pipeline - 745 miles of arctic grade 48" main line pipe. It is planned that pipe will be purchased in 40-foot lengths, and a central Fairbanks facility will be used for all double jointing (welding two 40-foot lengths of pipe into an 80-foot length), coating, and insulation.

-- Project Directorate - All Northwest Alaskan activities; Project Management Contractor management and consultants' activities; pre-certification efforts including cost sharing studies; third-party monitoring (State of Alaska, Department of the Interior, and Federal Inspector), and permits, insurance, and taxes.

b. Estimate Components

The base engineering estimate equals $7.08 billion, excluding all contingencies and an amount covering abnormal or unexpected events. In accordance with standard cost estimation practice, a contingency of 12 percent was then added to the base estimate to account for normal estimating uncertainty concerning accuracy of material quantities and prices, human productivity assumptions, equipment reliability assumptions, normal schedule variances, and the accuracy of bid specifications based on current project definitions.

The normal contingency was developed by segregating the base cost estimate into individual risk items and establishing variance ranges for each item. This data was statistically examined on a computerized risk analysis model.

In addition to these estimating uncertainties, Alaskan Northwest faces risks arising from abnormal or unexpected events that could affect project costs. Under the FERC approved IROR procedure, the risks posed by these abnormal events and the resulting potential costs are to be quantified to aid the FERC in establishing a target cost for the ANGTS for IROR purposes. This analysis was also performed to establish a target cost for financing purposes to determine the possible range of cost increases due to events not subject to Alaskan Northwest's control.

Alaskan Northwest carefully analyzed the potential cost impact arising from 36 abnormal or unexpected events, such as strikes and work slowdowns, abnormal weather, unanticipated pipeline mode changes, unanticipated changes in domestic and world markets for labor, materials, and services, unanticipated environmental conditions, contractor failure to perform, contractor bankruptcy, and others.

After the 36 abnormal events were identified, experts from Northwest Alaskan, Fluor, and selected outside consultants defined the probability of occurrence of each event classified as abnormal.

The same experts also evaluated the range of potential cost impacts if the event did occur. The assumptions in the engineering estimate which related to the event were reviewed, and values were established to represent the incremental costs of each event.

The cost ranges and probabilities for the 36 events were then used to determine the total potential impact of abnormal events on project costs. A computer simulation was employed to determine the range, distribution, and expected value of costs resulting from abnormal events. This simulation consisted of 1000 random samplings of each event. The results of this analysis indicate that such events could increase project costs by as much as $2.28 billion.

The Alaskan Northwest cost estimate, including the base estimate, contingency, and abnormal events, totals $10.2 billion in 1980 dollars excluding certain revisions to be filed shortly with the FERC and excluding finance charges, and has been the subject of intensive and in-depth analysis by the FERC staff, the Office of the Federal Inspector, the State of Alaska, and the three North Slope producers over the past fifteen months. The Federal Inspector retained Williams Brothers Engineering Company to assist in this effort. A final report on such estimate has been issued jointly by the FERC's Alaskan Delegate and the Division Director of the Office of the Federal Inspector and noticed for comment by the FERC. All comments have now been filed with the FERC, and a decision is expected to be issued in the near future.

B. Prudhoe Bay Gas Conditioning Plant

1. Design

The gas conditioning plant is being designed and engineered by the Ralph M. Parsons Company of Pasadena, California, which is the Project Management Contractor for the conditioning plant. Parsons is eminently qualified to design and engineer the plant, having more engineering experience at Prudhoe Bay than any other firm. In this effort, Parsons works closely with and under the supervision of Northwest Alaskan, which has been designated the operator under the terms of the Cooperative Agreement between the sponsors and major North Slope producers and which, as such, has responsibility for the day-to-day activities necessary to engineer and design the plant.

The plant will receive gas from the Prudhoe Bay producing areas and will condition the gas to pipeline quality by removing impurities, carbon dioxide, and heavier hydrocarbons. Because the pipeline will be operated as a chilled, high pressure line and because the first compressor station is at about milepost 80 of the pipeline, the plant will also refrigerate the gas to 30° F. and compress the gas to 1260 psig. The plant design is based on the SELEXOL process, a patented process licensed by the Allied Corporation (formerly Allied Chemical Corporation), for removing carbon dioxide and heavy hydrocarbons.

In addition to the conditioning facility, the plant will consist of an operations center, a 288-bed residential facility, a crude cooling unit, a river water intake station, a reservoir intake station, a flare and waste water lagoon area, construction pads, access roads, and miscellaneous pipelines.

Most of the plant conditioning facilities will be prefabricated as modules at construction sites on the West Coast and then shipped to Prudhoe Bay by ocean-going barges, where they will be assembled.

Parsons has performed a great deal of the design, engineering, planning, and cost estimating for the plant, having expended over 400,000 workhours to date in this regard.

The FERC environmental staff has prepared both a draft and a final environmental impact statement, which conclude that construction and operation of the plant at the Prudhoe Bay site are environmentally acceptable. The environmental impact statement has fulfilled all the National Environmental Policy Act requirements.

2. Cost Estimate

The cost and schedule estimates for the plant are similar to and patterned after those submitted to the FERC for the Alaska pipeline segment. The target cost for the plant is composed of a base engineering estimate and a contingency. The base engineering estimate has been cast into a work breakdown structure similar to that developed for the Alaska pipeline segment for cost control purposes. The contingency is also similar to that for the Alaska pipeline segment, except that it also covers cost impacts from abnormal events as well as normal estimating uncertainty. Examples of abnormal events that could cause the plant cost to overrun estimated costs are abnormally severe weather affecting fabrication sites, loss of a barge during the voyage to Prudhoe Bay, and a major fire at the plant construction camp. The total cost estimate for the plant, in 1980 dollars, is $3.6 billion excluding financing charges, but including contingency for the events described above.

C. Construction Coordination and Logistics for the Plant and Pipeline

Coordination of the design and engineering of the Alaska pipeline segment and the gas conditioning plant is performed by Northwest Alaskan as operator under the Alaskan Northwest partnership agreement and under the Cooperative Agreement. A Northwest Alaskan project team is located at the Irvine, California facilities of Fluor and works very closely with the PMC in connection with the design, engineering, and construction of the Alaska pipeline segment. A Northwest Alaskan project team is also located at the Pasadena, California facilities of Parsons where the plant is being designed and engineered.

The schedules for both the Alaska pipeline segment and plant are coordinated by Northwest Alaskan, with key dates and schedule requirements of the plant tied to the completion date for the Alaska pipeline segment. Meetings of the Technical Committee of the Design and Engineering Board, composed of representatives of the pipeline sponsors and producers, are held monthly. The Technical Committee receives progress reports on the Alaska pipeline segment and plant and makes recommendations to the Board on major issues affecting the pipeline and plant.

In addition, in order to eliminate or minimize delays or cost increases resulting from competition for resources between the Alaska pipeline segment and plant, a Resource and Logistics Committee was formed from members of the Northwest Alaskan pipeline and plant project management teams to identify areas where activities on one project could have an adverse impact on resources necessary for the other, such as craft labor availability, material acquisition, and transportation services.

To further reduce the potential for delays in the completion of the Alaska pipeline segment and plant, construction and material acquisition schedules have been planned to eliminate bottlenecks. The more difficult construction on the Alaska pipeline segment, such as laying pipe over Atigun Pass and major river crossings, will begin in advance of less difficult construction. For both the Alaska pipeline and plant segments, equipment with long lead times, such as compressors and refrigeration systems, must be ordered as soon as possible in order to avoid delay in the delivery of such equipment to the field. More particularly, plant equipment must be fabricated in the lower 48 states on a schedule that will assure it reaches Prudhoe Bay during the approximately six week period each summer that the Beaufort Sea is not ice bound. Additionally, 75 percent of the mainline pipe will be stockpiled in Alaska prior to the commencement of construction.

In the event that construction problems should arise, provisions have been made in the cost estimate for the Alaska pipeline segment, which is being reviewed by the FERC, and in the target cost estimate for the plant, which will shortly be submitted to the Commission, for additional costs necessary to overcome the problems. Thus, even if problems arise, notwithstanding our efforts to minimize the likelihood of their occurrence, the project has been planned and engineered in such a manner that they should not cause serious or extended delays in project completion.

V. ANGTS CAPITAL COSTS

The ANGTS will be constructed in two phases. The first phase, which is referred to as the pre-build, has been partially constructed and will be completed in 1982. When completed, this phase will include 1,500 miles of pipeline or about 30 percent of th[illegible]al pipeline system. However, it represents only about 8 percent [illegible] the total capital costs in 1980 dollars. The second phase involves completion of the remaining portions of the ANGTS by November 1986, assuming expeditious legislative and regulatory action by the second quarter of 1982.

Based upon this schedule, the total system is estimated to cost $17.5 billion in 1980 dollars excluding contingencies and financing costs. Contingencies have been added for possible normal estimating errors and for abnormal events which may occur. These contingencies and allowances for abnormal events, which vary for the conditioning plant and each major pipeline segment, total $5.5 billion in 1980 dollars and represent 31 percent of the base estimate. The 1980 dollar estimate of $23.0 billion, including contingencies, consists of \$3.6 billion for the conditioning plant, \$10.8 billion for the Alaska pipeline segment, \$5.8 (U.S.) for the Canadian segment, and \$2.8 billion for the Eastern and Western legs in the lower 48 states. Of the \$23.0 billion estimate, the pre-build phase of construction is estimated to cost \$1.7 billion and the second phase construction is estimated to cost \$21.3 billion.

Because these estimates are in 1980 dollars, it is necessary to add inflation and interest costs to estimate the amounts that must be financed. We have used a range of inflation and interest rates for this purpose from 7 percent to 11 percent and 10 percent to 14 percent respectively in the United States. The resulting range of cash requirements to construct the total system is \$38.7 billion to \$47.6 billion. The pre-build phase is estimated to be completed for \$2.4 to \$2.7 billion. Therefore, the net required amount to finance the remaining ANGTS facilities is \$36.3 to \$44.9 billion.

VI. MARKETABILITY

In order to determine the economic viability of the ANGTS, it is necessary to first estimate the delivered cost of the gas and then compare that to the cost of alternative fuels. The delivered cost of Alaskan gas will include all fixed and variable costs such as the wellhead cost of gas, depreciation, operating and maintenance costs, all taxes, return on equity and interest costs. These costs, when deflated to 1980 dollars, average from

\$4.65 to \$5.10 per million Btu's during the first twenty years of the project. Stated in constant dollars, this cost declines dramatically during the life of the project. For example, the delivered cost ranges from approximately \$9.20 to \$9.35 per million Btu's in the first year and from approximately \$2.75 to \$3.20 per million Btu's in the twentieth year. This dramatic decline occurs because of the amortization of the investment over the project life. Therefore, in real dollars, the cost of delivering Alaskan gas to consumers will decline significantly over the project life. This declining real cost is the basis for the bargain that Alaskan gas represents for the nation and should insure its marketability over the life of the project.

The factors which will be most influential in continuing a market for Alaskan gas are increasing constant dollar world oil prices, the demand for and declining availability of natural gas supplies in 1986-87 and thereafter, and the method by which Alaskan gas is priced to compete with oil.

The long term outlook is for an increase in real world oil prices. In an environment of rising constant dollar prices for oil, Alaskan gas will become increasingly attractive compared both to oil and to alternative gas supplies whose prices escalate with oil. Rising oil prices tend to stimulate the demand for gas at the expense of oil. Since a major portion of existing industrial and power generation plant capacity is designed for both oil and gas firing, rising oil prices quickly shifts demand to gas. In addition, prices for most supplementary gas supplies -- such as

Mexican and Canadian gas -- are linked to oil prices. Thus, rising real prices for oil make Alaskan gas -- the price of which is not linked to oil prices -- increasingly attractive relative to oil and to most other supplemental gas supplies. Finally, Alaskan gas will become an increasingly better buy than imported oil because as the real price of oil increases the real price for Alaskan gas delivered to U.S. consumers will decrease. The cost of Alaskan gas will decrease as depreciation reduces the rate base upon which transportation charges and related income taxes are calculated, which costs comprise the largest components of the delivered price of Alaskan gas.

Some estimates of future natural gas demand have been steadily reduced as a result of the extent to which natural gas demand has been responsive to increasing prices established by the NGPA. Although demand forecasts are down, the long-term outlook for production is down even more. Increasing drilling rates will be unable to offset the steady decline in gas reserves added per unit of drilling effort. As a result, the production rates will continue to decline. By 1987, when Alaskan gas will be available, the decline of conventional lower 48 gas supplies will have created a strong demand for Alaskan gas.

This supply-demand imbalance is illustrated in Tables III-I and V-I of the marketability study prepared by Jensen Associates, Inc., which is attached as Appendix E to my statement. Table V-I illustrates the forecasted demand for natural gas by residential and commercial sectors, industrial sectors, electric power generators, and other users through 1990. Table III-I shows the gas supplies projected to be available during the same time period from conventional and unconventional production, imports, synthetic gas, and Alaskan gas. Table III-I and V-I reflect market clearing after deregulation of new gas volumes in 1985.

The economic benefit of Alaskan gas is illustrated by the graph that I have attached to this statement as Appendix F. This graph shows the delivered cost of Alaskan gas for a range of assumptions regarding inflation and interest rates. Also shown is the estimated market clearing price for natural gas prepared by Jensen Associates, Inc. Two market clearing price estimates are shown. One is based upon the oil cost which Jensen expects would occur under the type of price formation typical of the 1970s during which occasional market disruptions periodically drove prices sharply higher. The other is based upon a lower bound possibility for oil prices. This graph shows that if only one major disruption occurs in the Mid-East resulting in significant increases in oil prices in the decade of the 1980s, Alaskan gas will be marketable from the very beginning of its availability. If a more conservative increase in oil prices occurs, there will be about three years when the Alaskan gas cost is higher than other supplemental gas supplies. However, in addition to the rolled-in pricing capacity afforded by the NGPA, there are other methods available which can be used to levelize charges for Alaskan gas to avoid this early-year problem, if required. We are confident that through a combination of the increasing real price of oil and, if necessary, such levelizing methods Alaska gas can be marketed commencing in 1987.

Concerns also have been expressed about the marketability of Alaskan gas under complete natural gas deregulation. In a deregulated environment, the price of Alaskan gas will adjust to the marketplace and be saleable. As stated above, the price in the early years can be adjusted if necessary through tariff and/or contractual provisions to assure that Alaskan gas is marketable.

VII. NATIONAL BENEFITS

The benefits of completing the ANGTS are self-evident. This vital transportation link will connect the lower 48 states to 26 trillion cubic feet of proven natural gas reserves, or 13 percent of all domestic gas reserves, and over 100 trillion cubic feet of potential reserves in Alaska. Once the ANGTS is in place, gas exploration activities will increase in Alaska and Canada making additional reserves available for transport. The ANGTS will deliver two billion cubic feet of gas per day initially and can easily be expanded to deliver 3.2 billion cubic feet per day.

Construction of the ANGTS can displace between 400,000 and 600,000 barrels of foreign oil per day for the next twenty to thirty years. The resulting savings in foreign payments for oil is in excess of $7 billion in the first year alone, assuming a conservative cost of oil of $50 per barrel in 1987. An even greater reduction in balance of payments will occur later as world oil prices rise, as Alaskan gas volumes increase, and as the delivered price decreases. These balance of payments savings will have a positive impact on the inflation rate.

The ANGTS will create jobs for U.S. workers and orders for U.S. businesses to provide materials, equipment, and services in connection with the construction and operation of the pipeline and related facilities. There will be a peak work force for the Alaska gas pipeline and gas conditioning plant of 16,000 workers.

As the Net National Economic Benefit Study prepared for the project shows, the present value of the Alaskan gas that the ANGTS will bring to the lower 48 states is likely to be between $90 and $140 billion. */ The total present cost of delivering this gas (including the wellhead cost of the gas) is approximately $50 billion over the 25-year project life. Accordingly, the present value of the net benefits of the ANGTS is between $40 and $90 billion for all U.S. parties associated with the project. For our base case, we use the median gas value of $110 billion, which yields a median Net National Economic Benefit of $60 billion. All of the above values are in January 1980 dollars, discounted in real terms at three percent to mid-1981.

In conclusion, the conservative direct net national economic benefit of the ANGTS -- economic benefits minus costs -- is in

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*/ These values are the mode and expected value for the gas value, respectively. The NNEB study is attached as Appendix G to my statement.

excess of $60 billion. This is simply the benefit derived from the market value of the gas and does not include the indirect benefits, such as increased energy independence, improved balance of payments, the creation of jobs, or the cost savings that would result if Alaskan gas prevents a repeat of the phenomenon experienced throughout the 1970s -- curtailments of industrial gas customers with resulting economic dislocations, including a loss of jobs, a reduction in taxes, and increases in unemployment compensation.

VIII. REMAINING GOVERNMENTAL AND REGULATORY APPROVALS

A. Alaskan Northwest

Alaskan Northwest must file with the Federal Energy Regulatory Commission a supplement to its prior filed application for a certificate to construct and operate the Alaska pipeline segment of the Alaska Natural Gas Transportation System. This supplement will include: (1) a plan for private financing and related materials including a cost of service study, a marketability study, and a net national economic benefit study which demonstrate the continued economic viability of the ANGTS; (2) amendments to its prior approved tariff which conform to the financing plan; (3) any necessary amendments to the prior approved partnership agreement to conform to the financing plan; and (4) minor adjustments to the cost estimates previously filed with the FERC in 1980.

Assuming the waiver proposed is enacted by Congress, Alaskan Northwest must also file an amendment to its prior filed application seeking certification of the gas conditioning plant and approval of a tariff governing recovery from the shippers of the plant investment plus a reasonable rate of return on such investment.

Pursuant to Sections 4, 5, 7, and 16 of the Natural Gas Act, the FERC is empowered to issue a final certificate to Alaskan Northwest if it finds that Alaskan Northwest is able and willing to provide the transportation service and to conform to the provisions of the Natural Gas Act and the Commission's rules and regulations, that the rates and charges of Alaskan Northwest are "just and reasonable," and that the proposed service "is or will be required by the present or future public convenience and necessity."

The Commission must examine a number of factors in determining whether issuance of the certificate is in "the public convenience and necessity." For example, the Commission must find that the project is economically feasible, that the project can be financed under terms acceptable to the Commission, and that the proposed tariffs are just and reasonable and in the public interest. One important point must be emphasized. Congressional approval of the proposed waiver will not relieve the FERC of its responsibility to satisfy itself that these requirements have been met prior to issuance of a final certificate to Alaskan Northwest.

Additionally, Alaskan Northwest also must obtain from the State of Alaska appropriate land use authorizations for those portions of the pipeline and conditioning plant that will be on lands in which the State has an interest.

B. Northern Border and Pacific Gas Transmission

In addition to issuance of a final certificate to Alaskan Northwest, the Commission must also issue final certificates of public convenience and necessity to the Northern Border Pipeline Company and the Pacific Gas Transmission Company enabling them to complete the non-pre-built portions of the U.S. Eastern and Western Legs of the ANGTS. The Commission review process and the legal requirements described above are equally applicable to these applications, and Congressional approval of the proposed waiver will similarly not relieve the FERC of the ultimate responsibility to ensure that these requirements have been satisfied.

C. Shipper Tracking

The shippers of Alaskan gas must seek Commission approval of tariffs which permit them to flow through to their customers the sales price of Alaskan gas and the conditioning and transportation charges to be paid by them under the FERC or the Canadian National Energy Board approved tariffs. While the Commission has not yet reviewed such tariffs, it has addressed the need for what is referred to as "perfect tracking." In its Orders 31 and 31-B approving the Alaskan Northwest and Northern Border tariffs, the Commission noted that the financial and economic viability of the ANGTS is dependent not only upon tariffs which assure a constant stream of revenue from the shippers to the ANGTS, but also upon adequate "tracking" mechanisms in the shippers' tariffs which will permit sufficient revenues to flow, without interruption, to each shipper from its customers to reimburse each shipper for payment of ANGTS costs. Specifically, in Order 31 the Commission stated at page 147 that it:

> . . .shares the project sponsors' assessment of the importance and relevance of the tariffs. The tariffs are indeed the "economic lifeline" of the project. There must therefore be a degree of certainty for project sponsors and potential financers adequate to ensure that there will be a flow of revenues sufficient to service debt and all other current expenses once billing has been allowed to commence.

With respect to shipper tracking, the Commission found at page 67 that:

> In order to further assure that revenues are adequate to cover the cost of service of the project, <u>the Commission's policy will be to allow automatic tracking of Alaska gas transportation costs in the tariffs of gas shippers</u> who are interstate pipelines under our jurisdiction. (Emphasis added).

Again, as with the other FERC filings, once the shipper tariffs are filed with the FERC, the FERC must review such tariffs under the standards of the Natural Gas Act and the proposed waiver does not restrict that review.

IX. FINANCING

The framework of the negotiations now under way to establish financing for the project and the related financial bases for the proposed waiver can best be understood by reviewing their historical underpinnings and development. Before detailing the evolution of the financing, however, it should be pointed out that the President's <u>Decision</u> reflected an expected cost of the ANGTS, as then defined, of $13 billion, and an expected date of first deliveries of gas of January 1983. While all parties understood that many governmental approvals would have to be obtained and that many agreements among the parties would have to be negotiated before construction could begin, nonetheless in 1977 it was anticipated that regulatory and policy questions would be answered in one to two years. Thus the 1977 cost estimate and the accompanying financing requirements were based on long-term debt costs of ten percent, cost contingencies of five percent, and cost escalation due to inflation was anticipated to be five percent annually.

In hindsight, the uniformly agreed upon assumptions underlying the 1977 cost estimate and the then-scheduled in-service date were unrealistic. But capital market conditions were stable in 1977, at least in comparison with today's environment, and government policies were stongly supportive of energy projects.

Much that was anticipated by the project sponsors and the government agencies which reviewed and confirmed the reasonableness of the assumptions underlying the project have not materialized.

A. Financing Parameters Established by the Federal Government

The President's Decision set forth the determination that the project could be privately financed and the conditions under which a private financing was expected to occur. A plan was proposed to share the risks and benefits of the project among its several beneficiaries in accordance with the following principles:

1. The project should be privately financed.
2. The equity investment in the project should be at risk under all circumstances.
3. Direct and major beneficiaries of the project should participate in the financing either directly or in the form of debt guarantees.
4. The burden of cost overruns should 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.
5. Tariff charges could not commence prior to completion and commissioning of the system.

The President's Decision also established other critical parameters for the financing plan: a prohibition of producer equity investment in the project; the exclusion of the conditioning plant from the ANGTS; and a prohibition of direct or indirect government financial support, including guarantees. Finally, the plan described in the Decision contemplated the "project financing" of all debt, i.e. the assets and cash flow of the project -- its economic viability -- would provide the principal source of credit to lenders. Sponsors were not expected to extend their corporate credit in support of the project's debt.

Following the Decision, the FERC undertook to clarify the provisions in the President's Decision regarding commencement of consumer billing. In Orders 31 and 31-B the FERC ruled that billing could begin after the Federal Inspector certified that all ANGTS pipeline segments were completed, tested, and proved capable of operating. "Tested for service," according to the FERC, did not require that the line be filled with gas or that actual deliveries of gas begin. Moreover, it is important to note at this juncture that there was not a requirement that the conditioning plant be completed and rendered capable of service as a prerequisite for billing commencement. Thus under current law billing can commence on all four pipeline segments even in the unlikely event that the conditioning plant is not completed, and even if actual gas deliveries have not begun.

B. Original Sponsor Financing Plan

The principal financing parameters having been established by the President's Decision, Alaskan Northwest and its financial advisors in early 1978 initiated the development of a definitive financing plan. The original plan contemplated the following key elements:

1. The construction capital for the Alaska pipeline segment would be raised on a project financing basis without corporate or government completion guarantees. Funding for the conditioning plant would not be the responsibility of Alaskan Northwest.

2. In the absence of completion guarantees, the risk of non-completion of the Alaskan pipeline would be reduced to an acceptable level as follows:

a. The project's final cost estimate would be subject to an independent risk analysis and an overrun probability assessment that would determine the amount of an Initial Pool of capital required to reduce to an acceptable confidence level the chance that the project would not be completed. Commitments for the equity portion of the Initial Pool would be provided by the project's gas transmission company sponsors. Debt commitments would come from U.S. and foreign commercial banks and U.S. insurance companies and equipment and material suppliers.

b. Commitments would also be obtained for a second capital pool, a Completion Assurance Pool, which would be available in the unlikely event that project costs exceed the Initial Pool. The Completion Assurance Pool would be drawn down based on periodic comparisons of actual to estimated construction costs to date. Commitments for the debt portion of the Completion Assurance Pool would be supplied by the Alaskan gas producers and the equity portion shared by the sponsors and the producers, in a manner consistent with the President's <u>Decision</u>.

c. Both capital pools would be irrevocably precommitted prior to the commencement of construction.

d. Whenever possible fixed price contracts for equipment and, perhaps, turn-key contracts for the construction of certain portions of the project would be negotiated. Such contracts would remove significant parts of the project from the risk of overruns.

3. Once completion was achieved, credit support for the project's debt would be provided through the FERC approved minimum bill gas tariff which would assure the payment of the project's debt service under all circumstances. Based on the tariff and a perfect tracking mechanism, financing commitments would be secured from institutional lenders for a portion of the commercial bank financing. In addition, public debt markets could also be used to refinance construction loans.

In summary, the plan was (i) to remove a major portion of the project's cost estimate from the risk of overruns through fixed price contracts and turn-key construction contracts; (ii) to obtain firm commitments for equity capital and supplier credits; and (iii) to secure irrevocable commitments for a Completion Assurance Pool of sufficient size to complete the project under any and all foreseeable circumstances. Debt commitments would then be obtained from commercial banks and institutional lenders subject to satisfaction of an extensive list of conditions precedent.

C. Efforts to Arrange Financial Support from the State of Alaska and the North Slope Producers

1. State of Alaska

Alaskan Northwest and its financial advisors devoted much of 1978 and 1979 to seeking the financial support of the State of Alaska, support which was envisioned by the President's *Decision*, in an amount of approximately $2 billion. The plan proposed to the State and supported by its Governor included the issuance by a state agency of $1.5 billion in tax-exempt debt, the proceeds of which would be used to purchase project debt. The rationale and appeal of this measure from the project's standpoint was that the State's offering would tap an otherwise unavailable segment of the capital market. Alaskan Northwest, as an issuer of taxable securities, is unable to raise funds from tax-exempt investors, many of whom who control large pools of capital. The proposal also contemplated the issuance of $500 million of equity securities to the State, the income of which would add substantially to the enormous economic, fiscal, employment, and social benefits that the State will realize from the project.

This specific plan was not approved by the State legislature, but a special committee was formed to analyze State financial participation. Alaskan Northwest would welcome the State's active participation in the financing.

2. North Slope Producers

Commencement of negotiations with producers was seriously delayed because of unsettled legislative and regulatory issues completely out of the control of Alaskan Northwest. First, there was the uncertainty surrounding resolution of the Natural Gas Policy Act of 1978. The NGPA, among other things, established the wellhead pricing of Alaskan gas, the duration of its regulation, and the manner in which it will be priced by pipeline purchasers. Secondly, the development of the Incentive Rate of Return mechanism, including the key rate of return parameters, was not fully completed until September 1979 -- two years after the President's Decision. Finally, FERC approval of the project design specifications for pipe diameter and design pressure was not final until January 1980. Only after all of these critical issues were laid to rest was it possible to prepare a definitive cost estimate for regulatory and financing purposes. Not until that point could truly meaningful discussions setting the framework for the producers' financial involvement in the project begin.

In the fall of 1979, a month after settlement of the Incentive Rate of Return proceeding, a financing plan was presented to the Alaskan Northwest partners for their approval, thereby setting the stage for the commencement of negotiations with the North Slope producers. This financing plan was essentially the same as that described earlier as the original sponsor financing plan and was fully in compliance with all of the requirements of the President's Decision.

The first meaningful indication of specific producer willingness to support the financing of the project became evident in late 1979. From the outset, the producers' principal requirements for involvement in the financing were (1) that the President's Decision be altered, by waiver or otherwise, to permit the producers to own equity with full and proportional rights and benefits of equity ownership, and (2) that the conditioning plant be included in the ANGTS with provision for inclusion of all gas conditioning and processing charges in the ANGTS gas tariff. Neither of these producer requirements were permitted by the President's Decision.

The Department of Energy, through the Secretary and the General Counsel, served as an intermediary between the sponsors and producers to assist in negotiations. By March 1980, after numerous meetings and lengthy discussions, an initial set of conceptual agreements between the sponsors and producers was reached.

The principal accomplishment of these efforts was a Cooperative Agreement adopted in April 1980 and signed in June 1980 providing for the joint funding by the producers and sponsors of design, engineering, and cost estimation work for the Alaska pipeline and the conditioning plant. A second agreement, a Letter of Intent (which is attached as Appendix H), was entered into by Alaskan Northwest and the producers committing all parties to work expeditiously towards arranging a private financing of the project.

By May 1981, Alaskan Northwest and the producers agreed to approach the financial community with a financing plan embodying the following concepts:

1. For purposes of financing, the "as spent" cost of the Alaskan pipeline will be $21 billion and of the plant

will be $6 billion. In addition, a pre-committed completion assurance pool of $3 billion will be formed.

2. The debt/equity ratio for all capital investment will be 75:25.

3. The investment limits of all participating companies will be defined from the outset. As a group, the transmission companies will provide equity in an amount not to exceed $5.25 billion. As a group, the producer companies will provide equity in an amount not to exceed $2.25 billion.

4. The Alaskan Northwest partners will own 70% of the pipeline and the plant, and the producing companies will own 30% of the pipeline and the plant. Equity commitments to the completion assurance pool will be made on the same 70:30 ratio.

5. Debt funds (pipeline and plant) will be sought on a project credit basis. The transmission group will be responsible for arranging for $15.75 billion in project debt. The producer group has accepted responsibility for arranging for $6.75 billion in additional project debt. The debt which the producers are responsible for arranging will be accorded terms and conditions equivalent to those accorded other project debt.

6. Each company's participation will be subject to satisfaction of conditions precedent, namely:

   -- The conditioning plant will be included as part of the Alaska segment of the ANGTS.

   -- Each company's investment will be limited to a sum certain defined in the financing plan.

   -- All debt and equity participants will issue firm commitments, acceptable to all other participants, prior to construction of the pipeline or plant.

   -- All necessary governmental approvals and authorizations will be issued and accepted by the participants.

   -- All parties are assured that the project is economically viable.

   -- All parties are assured that the Canadian segment will be financed and completed without U.S. commpany involvement.

-- Each financing layer will be afforded equal terms and conditions.

D. Comparison of Original Sponsor Financing Plan and Sponsor/Producer Agreement

The May 1981 plan deserves elaboration to be fully understood in relation to the original cost estimate and financing plan detailed in the President's Decision. The basic cost estimate in the plan reflects substantial cost additions over the $13 billion estimate in the President's Decision. These cost additions are comprised primarily of (1) the $6.0 billion conditioning plant not provided for in the 1977 plan, (2) costs resulting from the more extensive design features which evolved in the past four years in contrast to the cost of the design originally contemplated, (3) cost escalations resulting from the delay of four years in the anticipated completion date because regulatory proceedings took more time than had been anticipated in 1977, (4) the abnormally high rates of inflation experienced in the U.S. since 1977, and (5) the unusually high long-term interest rates prevailing in the last few years which now may be subsiding. To reiterate what was said earlier, the 1977 plan for the $10 billion project was based on a 1975 dollar year estimate, escalated by five percent per annum to year of expenditure with a contingency of five percent and interest costs of 10 percent.

The May 1981 financing plan differs in material respect from the original sponsor plan also because of the requirements of the producers as conditions for their financial support for the project. Further, the funding assumptions reflect the absence to date of State of Alaska support which had been contemplated by the President's Decision. And finally, the most recent plan, unlike that described in the President's Decision, utilizes supplier credits, and Eurodollar and foreign financing for the Alaskan facilities. This expansion of target capital sources provides an element of flexibility, and is necessary as a result of the growth of the financing requirements.

E. Position of U.S. Commercial Bank Lenders

On the basis of the agreement reached by Alaskan Northwest and the producers, the first formal presentation of an ANGTS financing plan was made in May 1981 to four major U.S. commercial bank lenders--Bank of America, N.T.&S.A., The Chase Manhattan Bank, N.A., Citibank, N.A., and Morgan Guaranty Trust Company of New York.

On August 28, 1981 the four-bank coordinating group advised the partnership of the results of its preliminary assessment of the financing concepts, the general availability of debt support for the project, and suggested certain modifications to the approach to financing which the partnership and the producing companies might consider. A copy of this letter, together with its attachments, is appended for review by the Committee as Appendix I. Without re-stating the contents of the August 28 letter in detail, inasmuch as the letter must necessarily speak for itself, it is nonetheless noteworthy for us to underscore certain of the banks' preliminary conclusions, which are, of course, subject to the various conditions and caveats expressed in the letter of August 28.

First, the banks believe that the project can be privately financed without government guarantees or participation.

Second, the banks believe that there will be funds available on a world-wide basis sufficient to provide debt support for the project, within the range of $12-18 billion.

Third, the banks believe that after completion, and when the ANGTS is operational pursuant to satisfactory tariff and tracking arrangements, the credit of the project itself will provide adequate assurances of debt service to the extent that the sponsoring companies will not be obliged to a continuing pledge of corporate credit.

These are very positive results. But this encouragement was tempered by the banks' advice that credit support will be required of the participating companies during the construction phase of the project. In this connection, the banks concluded that the completion pool of funds concept advanced by us will not be perceived by lenders generally to be acceptable, in and of itself, as a basis for debt support during construction. Consequently, the banks have concluded that the bulk of the funds needed for the construction of the project cannot be raised on that basis. Thus, they have advised us, as noted in the letter of August 28, that a modification of our financing proposal should be considered which will permit some degree of debt repayment assurance during the pre-completion phase, involving a combination of (1) acceptable debt assumption arrangements by the sponsors and producers and (2) acceptable commencement of billing provisions prior to completion of the overall system.

The reliance by the banks on corporate credit and limited consumer support during construction may permit a reduction in the external financing requirements for the project. Since there would be a source of repayment for the bulk of project debt, the need to provide pre-committed contingency financing (to assure project completion and/or debt repayment) can be reduced or eliminated and the hopeful mitigation of inflation and interest rates would result in further reduction. The amount of the latter reduction is, of course, subject to the completion of further definitive engineering and cost estimation work. The banks have concluded that ". . . if the required credit support can be arranged, the banks are of of the opinion that a modified plan may well provide the basis for private sector financing of the project."

As to the waivers of law deemed to be necessary by the banks, they have advised, in their letter of August 28, that the level of credit support required to raise the extraordinary amounts of capital to finance the project necessitates that ". . .[t]he debt [of the project] be supported by repayment assurances involving [among other things] acceptable commencement of billing provisions prior to the completion of the overall system."

In short, the banks have advised me that the billing commencement provisions set forth in the proposed waiver are a critical credit support--indeed the absolute minimum--feature required to raise the necessary funds. Passage of the billing commencement features of the waiver package will increase the willingness of the banks and other lenders to participate in the financing in terms of the number of lenders participating and the amount of each lender's commitment to the financing.

In consideration of the circumstances described earlier which have resulted in the extraordinary amounts needed for this project, and the conditions that have developed in our financial markets since the President's Decision--none of which was anticipated in 1977--it is not unreasonable to understand the necessity for providing the limited credit support that lenders are seeking through a separation of the Alaskan pipeline and plant facilities, and the Canadian pipeline segment, for purposes of billing commencement for debt service charges.

F. Risk/Benefit Sharing Objectives of President's Decision Fundamentally Preserved

While the billing commencement waiver insisted upon by the banks would appear to represent a departure from the principles of risk sharing established in the President's Decision, the sponsors, as well as producers, would also be contributing more credit support -- with all its consequential costs and risks -- than was contemplated in the President's Decision. The concept of risk sharing is preserved: because of the greater financial requirements and the more difficult circumstances in which this project must be financed, it is incumbent that all project beneficiaries contribute more to realize the substantial benefits of the huge Alaska energy resource.

To reiterate an earlier point, the waiver provision providing for commencement of billing as each segment is completed is not unprecedented insofar as consumer exposure is concerned. Under current law, the consumer would incur a continuing irrevocable obligation to pay certain ANGTS costs even if gas service did not commence. This would result if all four pipeline segments were completed and commissioned for service by the Federal Inspector but (1) gas was not delivered by the producers to the conditioning plant, or (2) the conditioning plant was not completed.

The proposed waivers represent a recognition of the current reality with respect to consumer risk, not a dramatic wholesale repudiation of the risk/benefit sharing concepts developed in the President's Decision. Consumers would commence paying only for completed segments; they would not incur an obligtion for uncompleted facilities. From the standpoint of consumer cost, the payment for cost of service charges as permitted under the proposed waiver will result in lower charges for gas to consumers over the project life. This will result because carrying costs will not be capitalized and paid for by consumers over the project life in the absence of consumer paymments.

Consumers will be the ultimate beneficiaries of this project, realizing the substantial benefits of a domestic long-term premium source of energy, one of the few supplemental energy supply programs offering declining costs in real terms over the next generation.

G. Impact of the Waivers Upon Private Financing

While there is much that can and will be done while the Congress is considering the proposed waiver of law, it is inescapably true that constructing and implementing a financing plan for the project cannot be accomplished in the absence of affirmative action by both Houses of the Congress on the waiver request. We can say to you categorically that if the waiver is not permitted, private financing is impossible.

Our views with respect to the proposed waiver are dictated by the stark realities of the world credit markets. It is not possible for the financing of this project to move forward so long as the producers of Prudhoe Bay gas are excluded from equity participation in the financing. The equity contributions of these companies, and their support of an appropriate portion of project debt during construction, is essential. The pipeline company sponsors do not have the individual or aggregate financial strength to shoulder the entire financing requirements of the project.

Similarly, it is not possible to construct financing for the project so long as the conditioning plant remains outside the system, subject to uncertainties of ownership, cost recovery, and integration of construction and operation. Gas cannot move through the Alaska Natural Gas Transportation System without the conditioning plant, a fact readily apparent to any prospective lender. The plant must be integrated into the system and covered by the certificate and tariff ultimately determined to be appropriate by the Federal Energy Regulatory Commission for the Alaskan facilities.

With respect to the waiver dealing with regulatory constancy, we cannot overstate our belief that private financing in the world capital markets cannot be successfully arranged unless it can be demonstrated that funds advanced to the project under a FERC-approved tariff and tracking arrangement will not be subject to later change. We would emphasize that the lenders to whom we must appeal will be asked to commit funds on the basis of project credit after the system is operational; they will be asked to lend on the strength of a revenue flow which is derived through FERC tariff mechanisms. If they cannot be reasonably assured that the credit which they analyze and appraise before committing to the project is not subject to change in the future, they cannot, in all probability, lend to the project to the extent that will be required for successful implementation of a financing plan. Under the present state of the law, they have no such assurance. In this regard, we have been made aware of an opinion rendered by the General Counsel of the Federal Energy Regulatory Commission to Chairman Sharp and Congressman Brown dealing with the issue of regulatory constancy, and I have appended to my statement a copy of this opinion for your review. (Appendix J). Given the views there expressed, and our own individual and collective experience in financing gas projects, we must advise you that it will be impossible for us to raise the billions of dollars of debt necessary to support the project if lenders are subject to a change in the rules of the game after their money has been committed and spent.

With respect to the impact on private financing of the waiver of law necessary to permit some flexibility in the commencement of billing for charges upon completion of the Alaskan facilities, we would offer these views. First, during the period of time when the ANGTS is under construction, the project has no revenue flow and essentially no credit in its own right to provide a basis for assurance to lenders that interest and principal will be paid. Thus, during the period of construction credit support must be arranged, and, in the banks' view, this support must come from the participating companies and, to a limited extent, from the consumer beneficiaries of the project. From our prior discussions with some of you and with your staffs, you are no doubt aware that we would have preferred a billing commencement waiver in terms which would permit maximum flexibility and maximum discretion within the FERC to approve, or disapprove, tariff provisions which would accomodate the details of the financing package which we are ultimately able to negotiate on a world-wide basis. But we understand that the degree of flexibility which we sought is not attainable, given the underst able reluctance of the Administration and many of you to sanction a massive shift to the consumer of the risk of noncompletion of the project.

It is our view that the proposed billing commencement waiver is the absolute minimum that will permit us to carry forward our work. Without this waiver we cannot proceed, and with it we can proceed only on the basis that the sponsoring companies will be called upon to assume greater obligations during the period of construction thar were originally envisioned by us. With the waiver we can proceed, and we will give our best effort to make the financing work within its constraints.

H. Present Status of Financing Negotiations

On the basis of the views which we have just expressed, we trust it is clear that further progress on the financing of the project is inextricably tied to favorable Congressional action on the proposed waiver of law.

Following the delivery of the banks' letter of August 28 to the partnership, intensive negotiations have taken place among the participants, dictated in large part by the expression of the banks' views that a modification of our financing concepts would be necessary. These negotiations continue, but in all probability cannot be concluded by unconditional commitments until the participants know the Congressional reaction to the proposed waiver of law. Certainly financing cannot be put together on the basis of producer participation if producer participation is unlawful. Certainly financing cannot be put together if there remains uncertainty as to the status of the conditioning plant. Certainly financing cannot be arranged until the spectre of regulatory change is laid to rest. And certainly there can be no definitive financing until the billing commencement issue is resolved.

Progress on financing also hinges on favorable FERC action on our cost estimate. Agreement on capital requirements must be attained, and Commission approval of the cost estimates is not yet in hand.

Despite these major uncertainties, each of which must be resolved by the Congress and the Commission at this stage, the companies which have supported this project for the past years, and which collectively have already spent almost $550 million, are prepared to continue in their strong support of the project. Billions of dollars will be committed by these companies in the form of direct equity contribution and in the form of debt support during construction.

At this juncture we remain optimistic that if the Congress permits the proposed waiver to become effective, and if the Commission reacts favorably to our cost estimate, the private party participants in the project can reach agreement upon the level and degree of equity and credit support which they can each contribute. The aggregate credit so committed, together with the tariff and tracking mechanisms necessary to provide a basis for project credit after the line is operational, will permit us to continue in our determined efforts to meet the challenge of financing this project.

Before addressing the specifics of the waiver package, I would note one further point. A private financing plan can be assembled in a manner that reflects a proper allocation of risks between the principal beneficiaries of the ANGTS--the North Slope producers, the Alaskan Northwest partners, and the consumers dependent upon the Alaskan gas. The project sponsors and producers are willing to continue to accept the risks of non-completion imposed upon them by the President's 1977 Decision because they firmly believe the project can be constructed on time and within budget.

X. PROPOSED WAIVER OF LAW

On October 15, 1981 President Reagan, acting pursuant to Section 8(g) of the ANGTA, transmitted to Congress a proposed waiver of law (attached as Appendix K) which would accomplish four specific purposes, all of which are necessary predicates to private sector financing: (1) permit both debt and equity participation in the project by the Prudhoe Bay producers; (2) include the conditioning plant in the ANGTS and in the certificate to be issued for the Alaskan facilities; (3) permit the FERC to approve, at its discretion, tariffs which will provide lenders with sufficient assurances of debt and/or equity repayment, after individual completion of the gas conditioning plant, the Alaskan pipeline segment, and the Canadian pipeline segment, to warrant their advancing the enormous sums needed for private financing;

and (4) enable the FERC to expedite the issuance of the final certificates for the ANGTS.

I shall now address in detail the reasons why a waiver of each provision of law is required.

A. Public Law 95-158 and the President's Decision

1. Producer Equity Participation

The President proposes to waive Section 1, Paragraph 3, and Section 5, Conditions IV-4 and V-1 of the President's Decision, Pub. L. No. 95-158, to permit producer participation in the ownership of the Alaskan pipeline segment and gas conditioning plant of the approved transportation system.

Conditions IV-4 and V-1 of the President's Decision presently prohibit producer equity participation in the ANGTS, limiting producers to providing debt or debt guarantees. Specifically, Condition IV-4 requires the Alaskan Northwest partnership to be open to anyone, except producers of Alaskan gas. Condition V-1 prohibits such producers from having an equity interest in the ANGTS or having any role in the management, control, or operation of the project.

Waiver of this provision of law would permit the producers to own a equity interest in the project. Despite recognition in the Decision that producers should participate in the financing of the project, the restrictions imposed on the producers by the Decision are incompatible with a meaningful producer contribution to financing. It is not difficult to understand why the producers are unwilling to make a considerable financial commitment to the project without participation in decisions relating to expenditure of funds. Without equity participation and its resulting voice in project management, the producers will not support the project with producer company funds. Without producer support private financing will be impossible.

Since the execution of the Cooperative Agreement and the formation of the Design and Engineering Board, the North Slope producers have been working with the Alaskan Northest partnership in reviewing the pipeline and plant design, the cost estimates, and financing parameters. Their contribution has been valuable given their experience with the North Slope production facilities and the Alyeska oil line. Their continued participation, beyond that required for financing, is needed to help ensure a timely, cost effective completion of the ANGTS.

Concern has been expressed that producer participation in the ownership of the pipeline could lead to restrictions on pipeline capacity expansion or on access to the pipeline by non-owner shippers. Alaskan Northwest is confident that these problems will not develop. First, the producers' equity position will be limited to a minority interest. Second, Section 13 of the ANGTA requires that the FERC include a condition in Alaskan Northwest's certificate which provides that any one who wants to transport gas in the ANGTS must not be discriminated against in the terms and conditions of service on the basis of degree of ownership, or lack thereof. Third, the FERC has jurisdiction under the Natural Gas Act to review any expansion of the capacity of the Alaska segment. Finally, the proposed waiver provides that the FERC, after consultation with the Attorney General, must find that producer participation will not create or maintain a situation inconsistent with the anti-trust laws or create restrictions on access to the ANGTS for non-owner shippers or restrictions on capacity expansions. Thus, the FERC will assure that the producers' involvement and participation is not inconsistent with the anti-trust laws.

2. Prudhoe Bay Gas Conditioning Plant

The President proposes waiver of Section 2, Paragraph 3 (the first sentence) of the President's Decision, Pub. L. No. 95-158, to include the gas conditioning plant in the approved transportation system and in the final FERC certificate to be issued under the Natural Gas Act, and the application of Section 5, Condition IV-2 of the Decision to such plant.

A Prudhoe Bay conditioning plant has been recognized as essential to permit the delivery of North Slope gas to markets in the lower 48 states. The ANGTS has special conditioning requirements for the gas to be transported through the system. Unlike existing gas pipelines, the Alaskan gas pipeline segment will be a high pressure pipeline transporting chilled gas. This requires extraordinary inlet compression and cooling and the removal of a greater than normal percentage of carbon dioxide, water and liquefiable hydrocarbons. Accordingly, gas processing costs for Alaskan gas are much greater than the processing costs that normally occur in the lower 48 states.

The producers' willingness to make a substantial financial commitment to the project also is predicated on the inclusion of the conditioning plant as a part of the ANGTS to permit a recovery of costs associated with constructing and operating the plant, plus a reasonable return on invested capital, pursuant to a FERC-approved tariff.

Inclusion of the conditioning plant within the ANGTS and the Alaskan certificate will require amendments to the pending Alaskan Northwest certificate application at the FERC and Commission review and approval of such application and the plant tariff. Inclusion of the plant in the system will give the FERC the opportunity and the authority to review the plant design and its estimated cost of construction and authority to review and approve the tariff provisions applicable to the plant governing recovery of the plant costs. Nothing in the proposed waiver restricts or modifies the Commission's responsibilities to review the application and tariff and to find that such tariff is "just and reasonable" and in the public interest prior to issuance of a final certificate.

Application of the incentive rate of return mechanism to the conditioning plant would substantially delay issuance of a final certificate. However, the actual construction costs will be reviewed by the Federal Inspector, and only prudently incurred plant costs will be recovered in rates.

3. Billing Commencement

The President proposes to waive Section 5, Condition IV-3 of the *Decision*, Pub. L. No. 95-158, to authorize the FERC to approve tariffs that permit: (a) reccvery of the full cost of service of the Canadian pipeline segment (i) upon completion and testing of the Canadian segment but (ii) not before a date certain, as established by the FERC, to be the most likely date for the entire approved transportation system to commence operation; and, (b) recovery of actual operation and maintenance expenses, current taxes, and amounts necessary to service debt, including interest and scheduled retirement of debt for both the Alaska pipeline segment and the gas conditioning plant (i) upon their individual completion and commissioning but (ii) not before a date certain, as established by the FERC, to be the most likely date for the entire approved transportation system to commence operation.

Condition IV-3 of the President's 1977 Decision prohibits any tariff which would require the purchaser or ultimate consumer to pay any charge with respect to the pipeline at any time prior to completion and commissioning of the entire pipeline system. In Orders 31 and 31-B the FERC approved a tariff for Alaskan Northwest which provides that upon completion and commissioning (a government agency declaration that the system is ready to operate) of the ANGTS, the risk of service interruption or project failure is assumed by consumers. Specifically, under Commission Orders 31 and 31-B the FERC approved tariff permits Alaskan Northwest to charge a rate which will recover actual operating and maintenance expenses, current taxes, and debt service, including interest and scheduled debt retirement (but not return of, or on, equity investment), upon completion and commissioning of the pipeline segments of the ANGTS, before gas is actually transported or before completion of the gas conditioning plant.

The proposed waiver would permit the FERC to approve, at its discretion and only after a finding that the public convenience and necessity is served, a tariff permitting billing to commence for each individual segment of the ANGTS -- the gas conditioning plant, the Alaskan pipeline segment, and the Canadian segment of the ANGTS -- upon their separate completion and commissioning, but not before a target operation date established by the FERC.

It is important to note that the FERC in effect has already approved a tariff which permits billing to commence upon completion of the Alaskan Northwest, Foothills, and lower 48 segments, but prior to completion of the plant. The proposed waiver further divides the Alaskan Northwest and Foothills segments for billing commencement purposes. It is also important to note that the proposed waiver would not eliminate the authority of either the U.S. or Canadian government to certify that completion and commissioning of each individual segment has occurred.

a. Risk Of Non-Completion Of Any One Segment

It is extremely unlikely that any segment would be completed and commissioned but another not be completed and commissioned. First, the project sponsors and regulatory authorities will assure coordinated construction. FERC Order 31-B states that: "The Commission expects that U.S. and Canadian monitoring authorities will be doing everything in their power to ensure that all facilities associated with delivery of Prudhoe Bay are completed simultaneously and that gas will begin to flow immediately upon their completion. The Commission expects to use its authority to facilitate attainment of that objective whenever possible". (Order 31-B at 69). In addition, "the various controls and oversight authority granted to the Federal Inspector encourage coordination and timely commencement of service." (Order 31 at 161); second, the most difficult portions of the project will be constructed first; third, the U.S. sponsors will not receive a return of or on equity until the entire system is completed and gas deliveries commence; fourth, anything but simultaneous construction would result in unnecessary carrying costs on money; and finally, no charges can be made before the target operation date, which will be established by the FERC as set forth in the President's proposed waiver.

b. Sponsor/Lender Risks

No charges can be assessed for any single one of the three segments until it is completed and commissioned. Thus, investors in such a segment would bear the loss associated with its non-completion. Consumers would pay the minimum bill for any completed and commissioned U.S. segment only after the target operation date and/or the full cost of service for the completed and commissioned Canadian segment, also only after such target operation date. If none of the three segments is completed and commissioned, the tariff does not operate, and consumers pay nothing.

Only when the entire system is completed and operating and consumers begin to receive Alaskan gas can Alaskan Northwest begin to earn a return of and on the equity it invests in the project. Thus, Alaskan Northwest and the producers' equity will remain at risk until gas flows and thereafter depending on the cause and extent of any service interruptions.

c. Consumer Cost

While the proposed waiver could require consumers to pay some of the costs of a portion of the entire system pending the delivery of gas, the average residential consumer would pay only $.32, $.80, or $.98 per month after the target operation date depending on which segment was not completed. The important point to remember, however, is that costs are being recovered currently thereby eliminating carrying charges that otherwise would be capitalized and paid for by consumers in rates over the life of the project. The FERC has recognized that this form of minimum bill actually reduces the finance charges to be borne by consumers when service commences. (Order 31 at 161).

d. Canadian Considerations

In May 1980, the National Energy Board of Canada, after extensive review and formal proceedings, found that a tariff would be needed in Canada which would allow the Canadian companies to charge their full cost of service when the Canadian segment was completed. The National Energy Board took this action before it approved the pre-build construction of a portion of the Canadian segment and related gas exports in order to ensure that the entire Canadian segment (500 miles of pre-build and 1500 miles of the remainder) could be financed and completed.

The U.S. government assured Canada that the entire project would be built and that the U.S. would permit the Canadian sponsors to charge for its segment when completed in exchange for the commitment by Canada to pre-build part of the system and deliver additional quantities of Canadian natural gas to the U.S. On July 18, 1980, President Carter sent a letter to Prime Minister Trudeau which said that the U.S. government remains committed to the project, that the U.S. government is satisfied the ANGTS will be completed, and that the administration would initiate action before the U.S. Congress to seek changes to laws that prohibit tariff payments from U.S. consumers to the Canadian sponsor upon completion of the Canadian segment of the ANGTS, but prior to the completion of the entire system. (See Appendix B).

e. Financing Considerations

A workable financing plan will require reducing the potential risks borne by the lenders to the maximum extent possible, given the magnitude of the capital required which, in turn, requires the greatest level of lender participation possible in terms of the number of lenders participating and the amount of debt provided by each lender. To attract such extensive participation mandates segmentation of the total system for purposes of billing commencement. For example, commercial banks and institutional lenders have legal and internal lending limits for any customer.

Additionally, lenders generally desire a varied portfolio to spread their risks among a variety of projects. The ANGTS sponsors are asking these lenders to commit an unusually large amount of capital to a single undertaking. If the debt repayment is structured as though the ANGTS was three separate projects for debt repayment purposes, this should reduce the lenders' perception of risks to a level which may facilitate development of a private financing plan.

Finally, the recent volatile nature of both inflation and interest rates has changed drastically the approach taken by lenders in assessing the amount of loans that can be made to any project and the repayment schedules. Institutional lenders are now less willing to make long-term commitments than they were a few years ago given the present day market conditions.

f. Conclusion

The proposed waiver on billing commencement honors our commitment to Canada. Were it not for this commitment, Canada would not have proceeded with construction of the pre-build. Moreover, the consumer risk associated with this proposed waiver is minimal because it is so widely dispersed and because non-completion or delay in the simultaneous completion of the entire ANGTS is unlikely. The risk to be assumed by gas customers will be spread over literally millions of households and commercial and industrial establishments. Finally, consumers have more to lose if the ANGTS is not built. Over the next 25-30 years, U.S. consumers will pay more for their energy requirements if they have to use imported oil instead of Alaskan gas. The ANGTS will provide a reliable supply of energy to the lower 48 states which will not be subject to OPEC price increases or embargo.

B. Natural Gas Act

1. Evidentiary Hearing Requirements

The President proposes that Section 7(c)(1)(B) of the Natural Gas Act, Pub. L. No. 75-688, be waived to the extent it mandates the use of formal evidentiary hearings on ANGTS and related applications.

If Alaskan gas deliveries are to commence in late 1986, the process of obtaining a final certificate pursuant to Section 7 of the Natural Gas Act must not be unduly delayed.

This proposed waiver would remove any mandatory requirement that the FERC conduct any further formal evidentiary hearings on the ANGTS. However, the FERC would retain the discretion to order a formal evidentiary hearing if and when necessary.

No project in the Commission's history has been more closely scrutinized than the ANGTS. Three years of hearings were held before the Federal Power Commission prior to the President's 1977 Decision. One and one half years were spent in hearings, both in Canada and the U.S., before the final "prebuild" authorizations were issued. The rulemaking process that led to the development of the Incentive Rate of Return mechanism and the approval of the Alaskan Northwest tariff consumed two years. The FERC, the Office of the Federal Inspector, and their consultants have spent over one year reviewing the Alaskan pipeline cost estimate. In addition to this extensive regulatory review, the project received close scrutiny by a diverse group of Federal agencies and the Congress pursuant to the Alaska Natural Gas Transportation Act of 1976. Every aspect of the project has been extensively examined.

Alaskan Northwest believes that the intense governmental review to date, the proven ability of the Commission to process effectively ANGTS matters through informal rulemaking procedures (notice and comment), and the inordinate delay that formal hearings would generate, suppport the grant of this waiver.

Approval of the proposed waiver would not relieve the FERC of its statutory responsibility under the Natural Gas Act to find that construction and operation of the remaining portions of the ANGTS would serve the public interest and is in the public convenience and necessity.

2. Regulatory Certainty

The President proposes that Sections 4, 5, 7, and 16 of the Natural Gas Act be waived to the extent that the FERC could otherwise change any rule or order to impair (i) recovery of actual operation or maintenance expenses, current taxes, and amounts necessary to service debt, including interest and scheduled retirement of debt, for the approved transportation system; or (ii) the recovery by purchasers of Alaskan gas of all costs related to the transportation of such gas pursuant to an approved tariff.

Sections 4, 5, 7, and 16 of the Natural Gas Act are the statutory authorities by which the Commission can suspend, investigate, establish, or modify the rates charged by Alaskan Northwest or the costs flowed through by the shippers to their customers.

The terms of Alaskan Northwest's cost recovery and that of the shippers will be finalized when the FERC issues its final certificates. Sections 4, 5, 7 and 16 of the Natural Gas Act could permit the Commission subsequently to modify the terms of the certificate in a manner which could impair the ability of Alaskan Northwest and/or the shippers to meet their financial obligations.

This proposed waiver would ensure the ability of the sponsors to maintain debt service and the shippers to pass-through their costs by limiting the authority of the FERC to change project and shipper tariffs after initial FERC approval in a manner that would impair the maintenance of debt service or preclude the recovery by shippers of any costs associated with the transportation of Alaskan gas. This does not mean that actual expenses would no longer be subject to continuing FERC review for prudency. Rather it only assures that there will be no impairment of debt service.

The cost recovery mechanisms for Alaskan Northwest and the shippers are the tariffs approved by the FERC and the Canadian National Energy Board pursuant to which the transportation companies charge the shippers for transportation service and the shippers, in turn, charge their customers for all ANGTS costs, including charges under the Foothills and lower 48 sponsor tariffs. As the Commission found in its Orders 31 and 31-B these tariffs are the "economic lifeline of the project." Because of the extraordinary risks attendant to the project and the enormous amount of financing needed, lenders will require satisfaction that, once approved by the FERC, the tariffs will not be subject to future regulatory action which would impair the recovery of debt. This could occur if the FERC was to limit the payments to Alaskan Northwest by the shippers or to limit the passthrough of shipper costs associated with the project to their respective customers.

The FERC has attempted to provide as much regulatory certainty as possible by approving a tariff that, in the event of a service interruption, would in all events assure a stream of revenues sufficient to service debt and pay operation and maintenance expenses and taxes. However, the FERC recognizes that it could be legally possible for a future Commission to modify this tariff. In a letter dated August 18, 1981 to the Honorable Philip R. Sharp, Chairman of the Subcommittee on Fossil and Synthetic Fuels, Committee on Energy and Commerce, U.S. House of Representatives, and the Honorable Clarence J. Brown, Ranking Minority member, Subcommittee on Fossil and Synthetic Fuels, Committee on Energy and Commerce U.S. House of Representatives, the General Counsel of the FERC has written that both he and the FERC Chairman agree with the assessment that potential lenders to the ANGTS need greater assurances on the matter of regulatory certainty than they have been supplied to date and that, under present law, this assurance cannot be provided by the FERC.

This proposed waiver is limited in scope in order to preserve a balance between the assurance of pipeline revenue recovery vital to lenders and the statutory obligation of the FERC to assure just and reasonable rates. This waiver would only prevent changes to the tariffs which would impair debt service for the ANGTS or preclude the recovery by shippers of costs associated with the transportation of Alaskan gas. Nothing in this waiver alters the nature and extent of the FERC responsibilities under the Natural Gas Act in reviewing the tariffs, as part of its certification process, to ensure that such tariffs are "just and reasonable" and in the public interest.

3. Status of Alaskan Northwest

The President has proposed a waiver of Sections 1(b) and 2(b) of the Natural Gas Act, Pub. L. No. 75-688, to the extent necessary to permit Alaskan Northwest and ANGTS shippers to be deemed natural gas companies within the meaning of the Act upon their acceptance of FERC certificates.

Section 1(b) of the Natural Gas Act states that "[t]he provisions of this act shall apply to the transportation of natural gas in interstate commerce . . . and to natural-gas companies engaged in such transportation . . . ." This section delineates the scope of activities which are subject to regulation under the Natural Gas Act. Section 2(6) defines a "natural gas company" as "a person engaged in the transportation of natural gas in interstate commerce . . . ."

Since neither Alaskan Northwest nor the shippers will physically transport Alaskan gas until completion and actual operation of the ANGTS, they may not be considered a "natural gas company" within the meaning of the Natural Gas Act, and therefore -- absent the waiver of these provisions of the Natural Gas Act --

would not qualify to collect charges under their FERC approved tariffs until gas actually begins to flow through the Alaskan Segment. To permit Alaskan Northwest to charge the minimum bill when the Alaskan pipeline segment or the conditioning facility is completed and commissioned, Sections 1(b) and 2(6) must be waived to the extent that they interpose a legal basis for any conclusion other than that Alaskan Northwest and the shippers will be natural gas companies upon acceptance of final certificates.

4. Export and Import Authorization

The President proposes to waive Section 3 of the Natural Gas Act, Pub. L. No. 75-688, to the extent any further authorization would be required for the export of Alaskan gas into Canada and the import of such gas into the lower 48 states.

Section 3 of the Natural Gas Act requires government approval prior to the import or export of natural gas to or from the U.S.

This waiver would permit the export and import of Alaskan gas without obtaining approval pursuant to Section 3 of the Natural Gas Act. Inasmuch as the President has already approved the export of Alaskan gas to Canada and the import of Alaskan and Canadian gas to the U.S. associated with the project, further governmental approvals should not be required.

C. Energy Policy and Conservation Act

The President proposes that Section 103 of the Energy Policy and Conservation Act, Pub. L. No. 94-163, be waived to the extent it would require further authorization for the export of Alaska gas into Canada and the import of such gas into the lower 48 states. Section 103 of the Energy Policy and Conservation Act requires government approval prior to the export of natural gas from the U.S.

This waiver would permit the import and export of Alaskan gas without obtaining approval pursuant to Section 103 of EPCA. Inasmuch as the President has already approved the export of Alaskan gas to Canada and the import of Alaskan and Canadian gas to the U.S. associated with the project, further governmental approvals are not necessary.

Conclusion

The ANGTS sponsors have worked diligently and ceaselessly over the last seven years to provide a transportation system to bring much needed natural gas from Alaska to the lower 48 states. The ANGTS can be built in a timely and cost-effective manner. The need for this vital transportation link is without question and its benefits are substantial. But time is critical.

Since Congressional approval of the President's Decision in 1977, the ANGTS sponsors both in Canada and the U.S. have spent approximately three-fourths of $1 billion - all of which is at risk - in the design and engineering of the ANGTS. Large additional capital expenditures and commitments must be made in the coming months to purchase the necessary supplies, materials, and equipment to keep the project on schedule. The

Alaskan Northwest partnership cannot justify risking additional substantial sums of money to keep the project on schedule absent the unqualified support of Congress expressed through the approval of the waiver transmitted by the President.

Additionally, the capital markets are not limitless. Project delay results in increased capital costs. The projected total completed cost of the ANGTS is approaching the capacity of the worldwide capital markets successfully to fund the project. If Congress does not act on the waiver this session, the capital costs of the project will escalate even further and our ability to secure adequate funds to complete the ANGTS will be severely jeopardized. Thus, the next step lies before you and the decisions that you make in the next several weeks will determine whether the project sponsors both in the U.S. and Canada can move forward to develop a private financing plan and complete this critically needed project.

THE END

APPENDIX A

PUBLIC LAW 95-158 [H.J.RES. 621]; NOV. 8, 1977

ALASKA NATURAL GAS TRANSPORTATION SYSTEM—APPROVAL

For Legislative History of Act, see p. 3313

Joint Resolution approving the Presidential decision on an Alaska natural gas transportation system, and for other purposes.

Alaska natural gas transportation system. Presidential decision. Congressional approval. 15 USC 719f note. 42 USC 4321 note.

Resolved by the Senate and House of Representatives of the United States of America in Congress assembled, That the House of Representatives and Senate approve the Presidential decision on an Alaska natural gas transportation system submitted to the Congress on September 22, 1977, 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.

Approved November 8, 1977.

LEGISLATIVE HISTORY:

HOUSE REPORTS: No. 95-739, pt. I (Comm. on Interior and Insular Affairs) and No. 95-739, pt. II (Comm. on Interstate and Foreign Commerce).
SENATE REPORT No. 95-567 accompanying S.J. Res. 82 (Comm. on Energy and Natural Resources).
CONGRESSIONAL RECORD, Vol. 123 (1977):
Nov. 2, considered and passed House and Senate, in lieu of S.J. Res. 82.
WEEKLY COMPILATION OF PRESIDENTIAL DOCUMENTS, Vol. 13, No. 46:
Nov. 8, Presidential statement.

APPENDIX B

THE WHITE HOUSE

TEXT OF A LETTER FROM THE
PRESIDENT TO THE
PRIME MINISTER OF CANADA

July 18, 1980

Dear Mr. Prime Minister:

Since you last wrote to me in March, the United States Government has taken a number of major steps to ensure that the Alaska Natural Gas Transportation System is completed expeditiously.

Most significantly, the Department of Energy has acted to expedite the Alaskan project. The North Slope Producers and Alaskan segment Sponsors have signed a joint statement of intention on financing and a cooperative agreement to manage and fund continued design and engineering of the pipeline and conditioning plant. The Federal Energy Regulatory Commission recently has certified the Eastern and Western legs of the System.

The United States also stands ready to take appropriate additional steps necessary for completion of the ANGTS. For example, I recognize the reasonable concern of Canadian project sponsors that they be assured recovery of their investment in a timely manner if, once project construction is commenced, they proceed in good faith with completion of the Canadian portions of the project and the Alaskan segment is delayed. In this respect, they have asked that they be given confidence that they will be able to recover their cost from U.S. shippers once Canadian regulatory certification that the entire pipeline in Canada is prepared to commence service is secured. I accept the view of your government that such assurances are materially important to insure the financing of the Canadian portion of the system.

Existing U.S. law and regulatory practices may cast doubt on this matter. For this reason, and because I remain steadfastly of the view that the expeditious construction of the project remains in the mutual interests of both our countries, I would be prepared at the appropriate time to initiate action before the U.S. Congress to remove any impediment as may exist under present law to providing that desired confidence for the Canadian portion of the line.

Our government also appreciates the timely way in which you and Canada have taken steps to advance your side of this vital energy project. In view of this progress, 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. The United States' energy requirements and the current unacceptable level of dependence on oil imports require that the project be completed without delay. Accordingly, I will take appropriate action directed at meeting the objective of completing the project

more

(OVER)

by the end of 1985. I trust these recent actions on our part provide your government with the assurances you need from us to enable you to complete the procedures in Canada that are required before commencement of construction on the prebuild sections of the pipeline.

In this time of growing uncertainty over energy supplies, the U.S. must tap its substantial Alaska gas reserves as soon as possible. The 26 trillion cubic feet of natural gas in Prudhoe Bay represent more than ten percent of the United States total proven reserves of natural gas. Our governments agreed in 1977 that the Alaska Natural Gas Transportation System was the most environmentally sound and mutually beneficial means for moving this resource to market. Access to gas from the Arctic regions of both countries is even more critical today as a means of reducing our dependence on imported petroleum.

Successful completion of this project will underscore once again the special character of cooperation on a broad range of issues that highlights the U.S./Canadian relationship.

I look forward to continuing to work with you to make this vital energy system a reality.

Sincerely,

JIMMY CARTER

# # # # #

APPENDIX C

96TH CONGRESS
2D SESSION

S. CON. RES. 104

CONCURRENT RESOLUTION

Whereas, the Alaska Natural Gas Transportation System is a critically important energy project that will tap Alaska's North Slope natural gas reserves which constitute more than 10 percent of this Nation's entire proven natural gas reserves;

Whereas, the System, when complete will supply the United States with 5 percent of its annual natural gas demand, displacing over four hundred thousand barrels of oil, thereby greatly reducing this Nation's excessive dependence on foreign oil;

Whereas, the Congress has already expressed its overwhelming support for the System in approving by joint resolution the President's 1977 Decision on the Alaska Natural Gas Transportation System;

Whereas, a portion of the System known as prebuild can be constructed by the end of 1981 to bring Canadian gas to this Nation until the entire system is complete in 1985;

Whereas, prebuild will contribute to completion of the entire System by spreading demand for capital, labor and materials over several years, and will enable this Nation to obtain Canadian natural gas to displace two hundred thousand barrels of foreign oil a day;

Whereas, the Federal Energy Regulatory Commission has issued decisions granting certificates for the prebuild facilities in the United States;

Whereas, the sponsors of the Alaskan segment of the System and the North Slope natural gas producers have entered into an agreement to fund and manage jointly the design, engineering and cost estimation for the Alaskan segment and have made a joint Statement of Intention to work to develop a financing plan for the Alaskan segment with the object of completing construction by the end of 1985: Now, therefore, be it

Resolved by the Senate (the House of Representatives concurring), That it is the sense of the Congress that the System remains an essential part of securing this Nation's energy future and, as such, enjoys the highest level of congressional support for its expeditious construction and completion by the end of 1985.

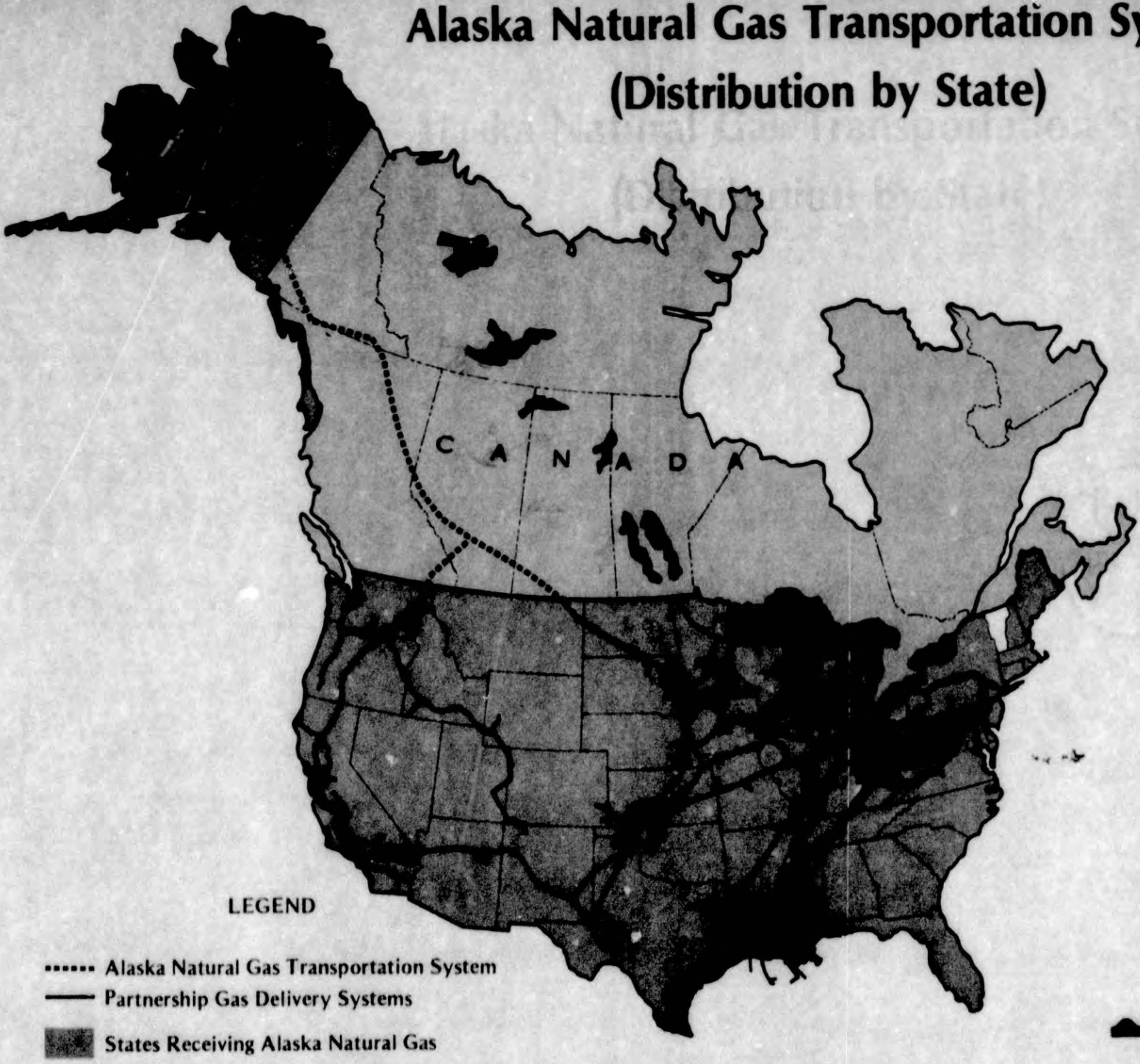
Passed the Senate June 27 (legislative day, June 12), 1980.

Attest:

Secretary.

APPENDIX D

Alaska Natural Gas Transportation System
(Distribution by State)



Northwest Alaskan
PIPELINE COMPANY

APPENDIX E

THE DEMAND FOR ALASKAN NATURAL GAS

JULY 1981

A Report to:

NORTHWEST ALASKAN PIPELINE COMPANY

Prepared by:

JENSEN ASSOCIATES, INC.
Boston Washington Geneva

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Boston, Massachusetts 02109
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Telex: 94-0057

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EXECUTIVE SUMMARY

Introduction

In September 1979, Jensen Associates, Inc. completed a study of "The Market Outlook for Alaskan Natural Gas" for Northwest Alaskan Pipeline Company. We have been asked by Northwest Alaska to review the marketability of Alaskan natural gas in greater detail and to update our conclusions in the light of events which have transpired since the first report. This study--like the previous one--was commissioned to review the purely commercial outlook for Alaskan gas, rather than to deal with the many aspects of national energy policy which necessarily influenced the decision to proceed with the pipeline. In focusing on the commercial marketability, the emphasis has been upon the likely gas market environment during the construction and early operation of the pipeline. Thus, its time frame is the decade of the 1980s.

Summary and Conclusions

The market environment for natural gas in the United States continues to undergo profound changes as demand, supply, price and the prospects for competitive energy sources all respond to the upheavals in energy markets which were set in motion throughout the world during the 1970s. By 1987, when Alaskan gas will be available, we expect that the decline of conventional Lower 48 (L48) gas supplies will have created a strong demand for supplementary gas volumes, if gas is not to lose market share to imported oil. In an environment of rising real prices for oil--which we believe is the most likely expectation for long-term price trends--the price structure for Alaskan gas will look increasingly favorable compared both to oil and to those alternative gas supplies whose prices escalate with oil.

We believe that Alaskan gas is marketable, not only under the rising long-term price increase scenario--which we term our "least unlikely" forecast--but also under a more conservative price projection which we have utilized in this study to test market response.

The underlying driving force which will be most influential in creating increased demand for gas in general, and a market for Alaskan supplies in particular, is an increase in real prices for world oil. A major portion of existing U.S. industrial and power generation plant capacity is designed for oil and/or gas firing and is not readily convertible to coal or other fuels. Thus, rising oil prices quickly shift demand to gas. In addition, prices of most supplementary gas supplies--such as Canadian, Mexican or LNG--are being linked to oil. Rising real prices for oil thus make Alaskan gas--without such linkage--increasingly attractive relative to alternate supplies.

Our "least unlikely" crude price forecast calls for a 60 percent increase in real crude oil prices between early 1981 and 1987 when the

Alaskan gas is scheduled to flow. Under such an oil price scenario, Alaskan gas--priced in the middle of its expected range--would be cheaper than oil-indexed imports from Canada, Mexico and Algeria by 1989.

Early 1981 has seen a marked shift in the outlook for world oil supplies and prices. The successful weathering by world oil markets of the Iraq-Iran crisis, together with unexpectedly high reductions in world oil --and OPEC oil--demand has forced many oil economists to moderate their projections. Most forecasters have lowered their near-term oil price estimates and some have substantially lowered their long-term estimates as well. We at Jensen Associates have also reduced our price expectations for the near-term and adjusted our longer-term "lower-bound" price scenario. But we are not convinced that the conditions necessary for the lower-bound forecast--continuing overhang of surplus oil supply within OPEC, and an absence of disruptive military or political events in the Middle East--will persist throughout the 1980s. We thus continue to regard the lower-bound case as less probable. We view a continuation of the world oil pricing patterns which prevailed during the 1970s as more probable. These call for at least one disruptive event and subsequent price increase between now and the time the Alaskan gas flows.

Roughly two-thirds of the time since early 1973, world oil supply has been in balance or in surplus, with a tendency toward stable or declining real oil prices. Yet, 80 percent of the oil price increase during the period occurred during those times when events in the Middle East upset world oil balances. The majority of the time there may have been--as there may be now--a natural tendency to ignore the dominant "crisis" element in world oil price formation.

Our least unlikely price projection, together with our less probable lower-bound case, are shown in Table 1. The least unlikely forecast is, of necessity, illustrative since one cannot predict the timing of disruptive events; for purposes of this forecast, we have arbitrarily projected a disruption in 1984, with price formation before and after the event forecast by analogy to the 1973/1974 and 1979/1980 disruptions. Our less probable lower-bound case has weakening real prices until the end of 1982, followed by the operation of the OPEC long-range strategy formula thereafter.

Much of our marketability analysis has been focused on the interaction of upper-bound Alaskan gas price estimates with lower-bound world oil price projections, in order to test the market under the least favorable combination of circumstances. World oil prices have already risen substantially since the passage of the Natural Gas Policy Act (NGPA) in November 1978 and crude oil price deregulation in January 1981 placed further upward price pressures on competitive oil prices.

While oil prices have risen, gas pricing, under the terms of the Natural Gas Policy Act of 1978, is to be controlled until new gas deregulation in 1985, thus creating strong pressures to drive dual-fueled demand to gas and create incentives for new customer growth and gas conversions. Thus, we see a growing demand for gas, despite major conservation-induced energy savings.

We do not see as easy an expansion of gas supply. Lower 48 production should continue to decline despite accelerated drilling activity. The addition of supplementary sources will be required to attempt to maintain supply levels. The supplements to maintain supply levels are apt to be costly, as increasingly, prices for gas imports from Canada, Mexico and LNG projects will be indexed to rising world oil prices.

The outlook for demand until 1985 is likely to be for a return of some of the excess demand conditions which first faced the gas industry from 1971-1977. New gas deregulation in 1985 will cause some price correction, and some loss of load, but a market will still remain for rolled-in Alaskan gas when it comes on line in 1987. Our estimates of gas demand together with supply (in the most severe, lower-bound oil price case) is shown in Table 2.

In the Natural Gas Policy Act, Congress granted Alaskan gas the right to rolled-in treatment for ratemaking purposes. This was designed to permit price-controlled old gas (which will continue long after 1985 new gas deregulation) to cross-subsidize any portion of the price of Alaskan gas over and above market clearing price levels. In a high oil price scenario, Alaskan gas quickly becomes competitive on the margin, as real oil prices overtake the initially higher-priced Alaskan gas. In our least unlikely combination of oil and gas prices, Alaskan gas requires little roll-in treatment during the early years to be marketable.

However, with projected Alaskan gas prices at the upper bound, and oil price expectations at the lower bound, Alaskan gas must rely--in the early years, at least--on the rolled-in treatment which Congress granted it in the NGPA. Assuming this relatively unfavorable combination of higher-bound Alaskan gas prices and lower-bound oil prices, we estimate that the 1987 market will have 25 percent of total U.S. gas supply still regulated below market clearing levels, amounting to a roll-in capacity of $11.7 billion. This is illustrated in Figure 1. Other supplementary gas supplies, priced above clearing levels, will utilize a portion of this capacity, but most of it remains to accommodate the Alaskan gas and to provide a potential for "flyup"--the rapid market and contractual escalation of deregulated new gas prices in 1985.

It is possible that the gas pipeline industry, through its contracting practices between now and 1985, can lock in enough deregulated gas price escalation to absorb the roll-in capacity in this lower-bound case and make it difficult to accommodate the Alaskan gas. We sense a growing awareness of this problem in the industry with greater emphasis on supply planning and on market protection contract clauses. We therefore believe the problem is manageable if dealt with in time.

In summary, we believe that a commercial market for Alaskan gas will exist in 1987. In our least unlikely world oil price scenario, Alaskan gas will increasingly be competitive with alternate gas supplies, which will be largely linked to oil. A combination of upper-bound Alaskan gas prices and lower-bound oil prices will require reliance on roll-in capacity, but enough capacity should exist to accommodate it.

TABLE 1

FORECASTS OF REFINERS' ACQUISITION COST OF CRUDE OIL

(1980 $/barrel)

	1981	1985	1987	1990
Least Unlikely Case[a]	$35.21	$59.30	$57.60	$66.42
Lower-Bound Case	$35.21	$36.19	$38.43	$42.01

[a] Assumes a disruption in 1984 with a sharp price increase followed by a period of market weakness.

Source: Jensen Associates, Inc.

TABLE 2

SUPPLY AND DEMAND FOR U.S. NATURAL GAS

1980 - 1990

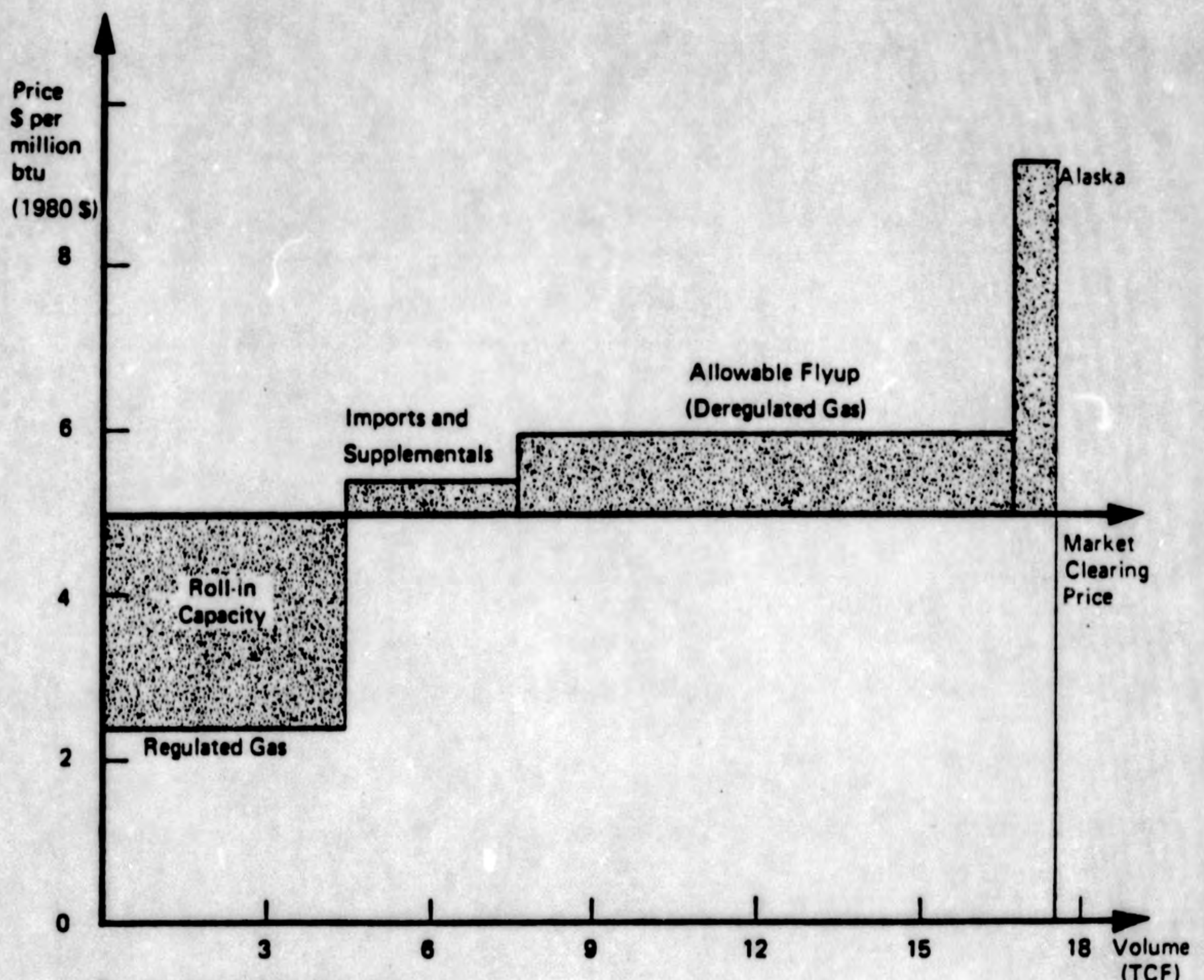
(Trillion cubic feet)

	Estimated	Forecast	
	1980	1985	1990[a]
Total Demand	20.5	22.5	18.4
Total Expected Supply (Excluding Alaska)	20.5	18.8	17.7
Shortfall			
Without Alaska	--	3.8	0.7
With Alaska	--	3.8	0

[a] The 1990 demand forecast is based on a cleared market for natural gas.

Source: Jensen Associates, Inc.
U.S. Department of Energy

FIGURE 1
1987 ROLL-IN CAPACITY OF U.S. NATURAL GAS MARKETS
(Based on Lower Bound Crude Price
and
Upper Bound Alaskan Price)



Source: Jensen Associates, Inc.

I. THE MARKET ENVIRONMENT FOR ALASKAN NATURAL GAS

Energy markets have been changing rapidly during 1981. The natural gas shortages of 1976/1977 have been replaced by a persistent "gas bubble;" the chaotic 1979 world oil markets which followed the Iranian Revolution have been supplanted by an "oil glut" with visible evidence of strain within OPEC. Energy price signals now often point downward, rather than consistently upwards as they have in the recent past. It is tempting to believe--as the popular and business press frequently observe--that world energy problems are on their way to solution and that complex and expensive energy supply options from nuclear power, to synfuels, to LNG, or to Alaskan gas may no longer be commercially justified.

We disagree with this hypothesis. The energy markets of 1987, when the Alaskan gas will be available to the Lower 48, are likely to be far different from the energy markets of 1981. The improvements in natural gas and oil balances have come predominantly from the demand side, partly through demonstrated levels of conservation which are much larger than most forecasters would have anticipated, but also through general weakness in economic activity both in the U.S. and the rest of the OECD. Improvements in energy supply for the most part have been disappointing, certainly, relative to expectations for supply five to ten years ago.

To the extent that portions of the U.S. natural gas and world oil surpluses are recession-induced, any pickup in economic activity threatens to restore some of the tighter energy market conditions which previously prevailed. This, in our view, is a much more likely expectation than a persistence of gas and oil surpluses through the latter part of the decade.

There are three critical elements determining the marketability of Alaskan natural gas. They are:

- the evolution of natural gas demand in the U.S. within the context of total U.S. energy market balances;
- the expectation for alternative gas supplies, both from traditional Lower 48 sources, as well as from imports and the gas supplements;
- and--since on the margin most gas competes with oil--the outlook for world oil price levels.

Our analysis suggests that gas demand will rise between now and 1985, as gas prices remain price-regulated under the NGPA and oil prices are deregulated. New gas deregulation after 1985, however, will diminish the comparative price advantage of gas. As a consequence, the price-sensitive demand for gas will shift to other fuels, thereby eliminating the excess demand for gas.

The outlook for gas supply, in our view, is for a continuing decline in Lower 48 production, with a resulting need for supplementary gas supplies to meet demand.

Rising real oil price levels have two interrelated effects. They increase the relative demand for gas compared to higher-priced oil; and they render most other supplementary supplies--which are for the most part price-indexed to oil--increasingly costly relative to Alaskan gas. Higher oil prices--as in our least unlikely oil price case--quickly make Alaskan gas competitive in its own right. In a more conservative lower-bound oil price projection, this competitive crossover point is delayed and Alaskan gas must resort in the early years to the roll-in treatment which Congress granted it in the NGPA.

The Evolution of Oil and Gas Markets during the Seventies

The commercial market for natural gas during the 1970s has been extremely complex. Projections and estimates made by normally knowledgeable observers have been frequently overtaken by events in a matter of months. We believe that the turmoil in natural gas markets is more likely to increase than to decrease during the 1980s, as the supply and price of both oil and gas are heavily affected by regulatory and political pressures, as well as the operation of the usual market forces.

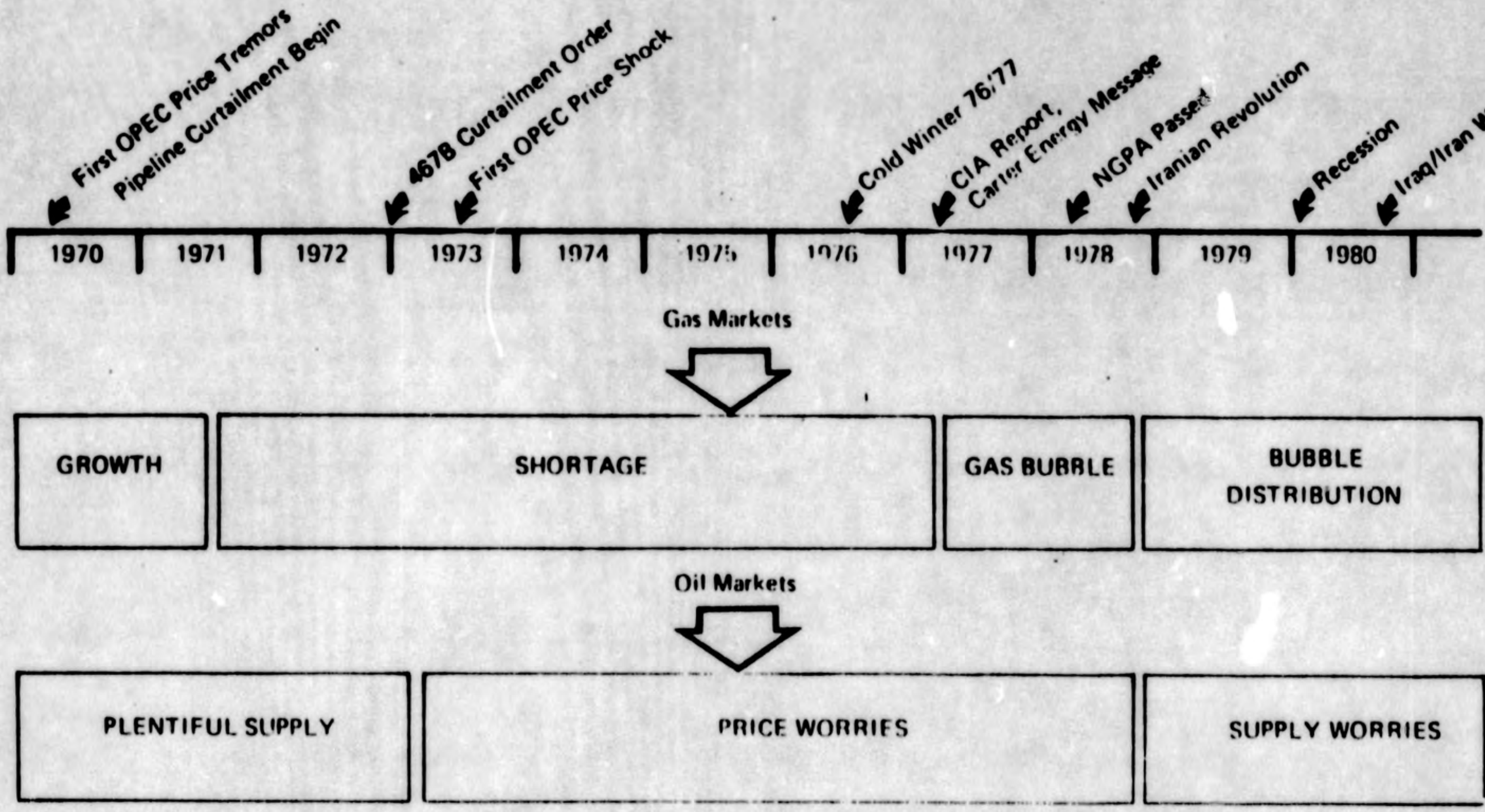
Jensen Associates identifies four major gas market environments during the seventies which we call the "growth," "shortage," "gas bubble," and "bubble distribution" periods. Figure I-1 depicts the chronological evolution of these markets over the last decade.

From the end of World War II to 1971, natural gas was the fastest growing energy source in the United States. When the 1954 Phillips decision of the U.S. Supreme Court placed interstate gas wellhead prices under Federal Power Commission control, gas prices were no longer influenced by changes in unregulated coal and oil prices. As a result, gas--in a period when supply was not perceived as limiting--carved out substantial increases in market share at the expense of competitive fuels. By 1971, the major interstate natural gas pipelines were no longer able to satisfy the growing demand for natural gas and an era of interstate natural gas pipeline curtailments began.

The growth period for natural gas, which effectively ended with the first interstate pipeline curtailments in 1971, was a period when relatively little concern was expressed about the availability or pricing of oil. Indeed, there was often little recognition of the fact that most oil on the margin had to be imported.

The natural gas shortage period, from 1971-1977, was an era when regulation sought to restrain the demand for natural gas to its clearly limited supply. This was accomplished by moratoriums on the attachment of new

FIGURE I-1
THE EVOLUTION OF GAS/OIL MARKETS



customers and by end-use curtailment mechanisms, which allocated shortages primarily among large industrial and power generation customers.

Perceptions about international oil supply and price changed substantially during this period. The Arab oil embargo of 1973/1974 led to a quadrupling of international oil prices by OPEC and public attention tended to focus on price rather than supply. It was common to characterize OPEC as a cartel which would ultimately break up and bring prices back down to "reasonable levels." A little recognized by-product of the natural gas curtailment priority system was that most of the curtailed gas demand in fact switched to oil. Our figures suggest that between 1972, the peak year of gas deliveries, and the passage of the NGPA in 1978, 76 percent of the fuel switching from gas was to oil, which on the margin had to be imported.

During the gas shortage period, the large overhang of excess gas demand at prices well below oil led gas suppliers to try to make up the shortages with alternative supplies, almost without regard to price. The fact that any new supply--such as comparatively high-priced SNG made from oil feedstocks--could be averaged with price-controlled supplies and still keep prices to the customer below market clearing levels, led to the phenomenon of rolled-in pricing, where high-cost gas could be averaged with price-controlled gas without loss of market share.

The logic surrounding the Natural Gas Policy Act of 1978 was born out of the shortage period. The winter of 1976/1977 had been abnormally cold, particularly in the upper Midwest. For a time it appeared that the worst gas shortage fears had finally materialized, with a cut-off of gas to industry and schools resulting from a seeming breakdown of supply. In retrospect, the winter of 1976/1977 appears to have been more a severe winter peak-demand problem that the system was no longer able to handle, than the chronic annual shortage which was increasingly anticipated during the shortage period. To enhance domestic supply, the NGPA liberalized price controls on many categories of gas, pointing towards deregulation of new gas by 1985. It did attempt to eliminate the dual market between intrastate and interstate gas by applying price controls to new intrastate gas for the first time and making the movement of gas from intrastate to interstate markets more flexible. The Act also introduced incremental pricing, which was in part designed to prevent undisciplined price behavior--through roll-in--in a tight market by threatening loss of industrial load. However, because of the desirability of Alaskan natural gas, that source was given a special exemption from incremental pricing, allowing it to be rolled-in.

By the time the Natural Gas Policy Act became law in November 1978, natural gas markets were already nearing balance, and talk of the "gas bubble" became common. In retrospect, it appears that conservation, principally by industrial users but also by residential and commercial customers, was much greater than most observers had anticipated. One of the major contributions to the bubble was the very substantial conservation which occurred in the intrastate market. Although gas production levels went down, demand levels dropped even further, creating a surplus from the demand side which was potentially available for the interstate market.

Our analyses suggest that at the time of the passage of the NGPA, no more than 1 trillion cubic feet (tcf) of the 2.3 tcf drop in industrial demand had switched out of natural gas into alternate fuels over the 1972-1978 period. Conservation accounted for the remainder of the net demand effect. Furthermore, in late 1978, a surplus of comparable size existed in the intrastate gas market as conservation had reduced demand below available supply and producers were reluctant to commit the surpluses to regulated interstate pipelines.

Our analysis suggests that in late 1978, the market was near balance and might well have cleared quickly had the NGPA simply provided for flexibility in moving gas from intrastate to interstate markets without all of the NGPA's complex pricing features. The simultaneous occurrence of the Iranian revolution and subsequent increase in world oil prices, however, has recreated a situation in which regulated gas prices fail to track competitive oil market prices.

The easing of the gas shortage and the emergence of the gas bubble coincided with growing concern about international oil. Oil concerns from 1973-1977 were largely about prices based on the view of OPEC as a price-fixing cartel which should be "broken up." President Carter's energy message in April 1977 publicly raised the possibility of oil shortages as well. It called upon an analysis by the Central Intelligence Agency which argued that deteriorating Russian oil supplies would put the Russians into competition for Middle East oil by the early to mid 1980s and create the possibility of physical shortages. Thus, attention shifted over the period of 1973-1977 from cartel-oriented price worries to genuine concern about physical supply. Ironically enough, by the time the NGPA was passed, its implied concern about excess gas demand and the threatened use of oil competition to discipline gas prices had largely been replaced by concern over the management of oil imports.

Among the measures which the Department of Energy (DOE) initiated to deal with oil shortages was the Order 30 program. This was designed to put surpluses of natural gas--the gas bubble--under interstate boilers to back out imported oil. Thus, where oil had been used as an agent to control excess gas demand during the gas shortage period, the gas bubble was being used as a device to control oil imports.

During 1979, while the international oil spot market was rising rapidly and the official OPEC prices rose two-and-one-half fold, we at Jensen Associates believed that the U.S. was entering a fourth market period we called "oil crunch." We anticipated that the rapidly emerging disparity between oil and regulated gas prices would cause a surge of conversions to natural gas, absorb the bubble, and recreate the conditions for shortage. In our forecast of natural gas markets for Northwest Alaska in 1979, we described this "crunch" phenomenon as creating a substantial, strong future outlook for gas demand, although the hard statistical information to demonstrate that it was occurring was not yet available.

From the vantage point of December 1980, it now appears that the gas surplus has remained with us and the "crunch" phenomenon anticipated by Jensen Associates in mid 1979 has not occurred as previously expected. A recap of the developments in the market from 1978-1980 suggests that the onset of the recession had a significant effect in holding demand below capacity levels. While the recession, as measured by changes in the Gross National Product, was slow to make its appearance during 1979, many energy-intensive industries such as cement, steel, and refining were selectively hit early. This caused a reduction in total industrial energy demand below what might have been expected on the basis of economic conditions alone. Thus, we have changed our designation of the period from 1978-1980 from "oil crunch" to "bubble distribution."

Examination of the figures for the period from 1978-1980 suggests that, indeed, a major shift in the bubble from the intrastate to the interstate market took place. Since intrastate markets were limiting production levels prior to the NGPA, gas which would normally have been produced for intrastate customers was cut back. The passage of the NGPA permitted this gas, which previously would have gone intrastate, to flow to interstate markets giving the appearance of a supply improvement. This production increase was due less to basic supply improvement than it was to the increased flexibility to move gas outside the producing state. We estimate that between 1978 and 1980, total gas demand actually supplied (on a weather normalized basis) increased by slightly over 1.5 tcf. Approximately a quarter of the increase occurred in residential, commercial and high-value industrial markets. More than half of this high-value gas demand increase occurred in the Northeast where the contrast between the prices of traditional oil fuels and price-controlled natural gas was the most dramatic. This increase, we believe, was truly a "crunch" effect. However, three-quarters of the increase in demand occurred in boiler fuel and power generation uses--principally in interstate markets--where curtailment-induced fuel switching was concentrated. This was the "bubble distribution" effect made possible by the more flexible intrastate/interstate gas transfer arrangements contained in the NGPA.

The Likely Natural Gas Market Environment during the Eighties

During the 1970s, the development of new natural gas market environments, which resulted from changing patterns of supply, demand, and pricing for oil and gas were sometimes surprising. Clearly, one cannot discount further surprises during the 1980s. Already, for example, 1981 has provided a largely unforeseen drop in world oil demand sufficient to reduce net requirements for OPEC oil to the lowest level since 1970, and to stimulate significant weakening of international oil prices. But many of the forces which will determine the market environment for Alaskan gas in 1987 are already in evidence. They suggest to us that energy markets in 1987 will be much different from energy markets of 1981, and that a commercial market will exist for Alaskan gas at that time.

Energy markets in mid 1981 are characterized by surplus--a persistent bubble in U.S. natural gas markets and a substantial international oil surplus. The oil surplus is the most recent development and one which has caught much of the industry by surprise. The world has weathered the Iraq-Iran war this past winter with no more than a minor flurry in the spot market in October/November, and emerged with evidence of a sizable market reaction to the price increases of 1979/1980. Free world oil demand this year might be no more than 46-47 million barrels per day, off about 3-4 million barrels per day from last year's levels. Net demand for OPEC oil could fall as low as 23 million barrels per day against an allowable OPEC capacity level of 30 million barrels per day. Total energy demand growth has fallen significantly below expectations and strong growth in both other energy sources and in non-OPEC oil have resulted in the sizable OPEC reduction.

In one view, this sudden change is more a reaction to faltering economic performance throughout the OECD than it is evidence of a new trend to deeper and more lasting demand response to higher price levels. World energy demand, and net demand on OPEC, both reacted to the sharp oil price increases of 1973/1974 only to resume a lower level of upward growth with an improvement in world economies in 1976. The nature of new increments of coal or nuclear capacity is that they are apt to be utilized first--as lowest in running cost--when total demand falters, thus levering oil demand downward in a recessionary year. But oil demand can readily return again as the economy strengthens. This pattern is being intensified during 1981 by the emergence of inventory liquidation of the excessively high world oil stocks which were built up in the market panic of 1979/1980. We look for a turnaround in OECD economic performance and in world oil demand by the early part of 1983, with a return of some supply insecurity and rising prices beyond that point.

We believe that the gas bubble will also begin to disappear as the U.S. economy develops some strength by 1983. Thus, the pattern which we foresee for 1983 and 1984--a return to conditions of excess gas demand--will characterize the middle years of the gas market before Alaskan gas flows to the Lower 48. The excess gas demand will be in response to the gas price controls retained under the NGPA, concurrent with domestic crude oil price deregulation (January 1981), which allowed prices to rise to international levels.

For gas, we have assumed that wellhead pricing will operate under the price constraints of the Natural Gas Policy Act through 1984. As presently envisioned, Section 102 gas--gas newly discovered since April 1977--will be deregulated, along with several other categories, and allowed to seek its own market level at that time. The original Congressional intent appears to have been to retain price controls on domestic natural gas while supply improvement was allowed to reduce the overhang of excess demand. The complex regulated gas price trajectories were to intersect with competitive fuel levels, so that an orderly transition to deregulation could occur in 1985. Clearly, the price levels, which Congress may have expected to provide an orderly transition in 1978, are totally unrealistic in 1981 after the oil price increases of 1979. While U.S. gas prices rose during 1979 at an almost unprecedented average rate of 3.4 cents per million Btus per month, the refiners' acquisition cost of crude oil in the United States rose at 15.4 cents per million Btus per month. Even residual fuel oil, which suffered price weakness from gas competition in a number of sections of the country, rose an average of 6.3 cents per million Btus per month. Thus, the gas price trajectory in the NGPA clearly failed to track competitive fuel levels in 1979. In our view, it will continue to fail to track the likely price trajectory of refiner acquisition cost of crude oil during the early 1980s. That suggests a significant price readjustment may take place in 1985 upon new gas deregulation, unless the supply of gas was so large as to set its own internal market clearing price structure without regard to competition from oil. In our view, this is extremely unlikely.

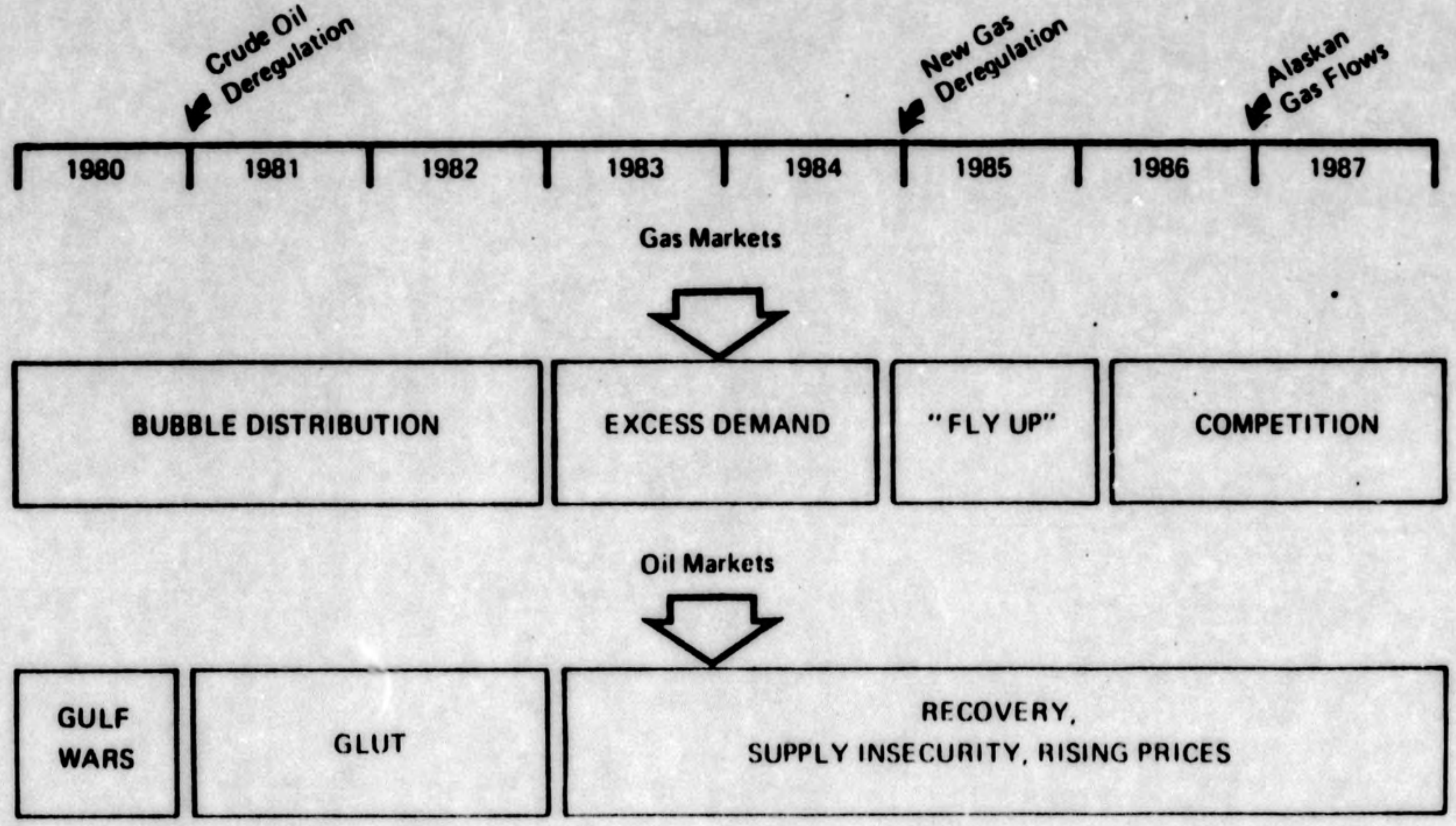
In projecting the evolution of gas/oil markets through the coming decade, the first new market environment which we envision is the return of excess gas demand. This is illustrated in Figure I-2. As the disparity between price-controlled natural gas and international oil prices continues, those customers with gas capability will increasingly prefer gas. In our view, this pattern was beginning to emerge during the 1979 oil price runup, but the creation of excess demand was blunted by the recession. But with a recovery from the recession, industrial demand should be restored. The economic driving force compelling dual-fuel demand towards gas will steadily mount.

Our detailed analysis of the demand potential suggests that gas demand would increase by 2 tcf between 1980 and 1985, if it were not constrained by supply. This is a demand level that the gas industry has not reached since 1973. Increasing conservation will limit the overall growth of residential and commercial demand. Growth in large boiler fuel and power generation uses will, we assume, continue to be restricted by federal regulation. Thus, the bulk of growth in demand would normally take place in high-valued industrial uses, primarily process gas. We estimate that about three-quarters of the overall demand increase will take place in the premium industrial fuel sector. The West South Central region, where most intrastate gas has been concentrated, has continually provided the largest increment of industrial demand growth and our projections assume that this will continue. One effect of the NGPA has been to control intrastate gas prices below competing fuels where intrastate markets were previously free to clear. Thus, the NGPA has created a financial incentive in both intrastate and interstate markets for industrial gas demand to grow.

The argument has frequently been advanced that many industrial gas users are reluctant to commit new or expanded installations to gas because of the potential unreliability of supply. The extent to which this threatened behavior is actually being practiced is debatable in our view. But,

FIGURE I-2

THE EVOLUTION OF GAS/OIL MARKETS DURING THE 1980's



the demand may not develop as we project unless the gas industry makes a credible statement about its supply potential during this period. Nevertheless, the disparity between regulated natural gas and alternate energy prices will provide an economic incentive for the high-valued industrial demand to utilize natural gas, whenever it is available.

Our projections for supply are not so optimistic. Lower 48 natural gas reserve additions have been less than production for twelve years. We do not expect reserve additions to rise to present production levels, despite accelerated drilling during the forecast period. For this reason we see a continuation of the steady decline of proved reserves.

The rate at which existing reserves are being depleted has been increasing in recent years. Part of this has been the result of intensive developmental drilling for higher producing rates. Some of it is also attributable to the concentration of discoveries in geological areas such as South Louisiana, where unconsolidated sands provide high permeability and extremely high well flow rates. Much of the newer reserves which will be added in other areas are not of such high permeability and therefore may not be subject to such rapid depletion. We anticipate that depletion rates will level out and, in fact, might well decline somewhat as the shift in exploration takes place. Thus, in our view, production from the Lower 48 States will continue to decline with declining reserves. The burden of maintaining supply will shift more and more to supplements such as imported gas, coal gasification or the Alaskan gas project under analysis here. Because of the lag times associated with many of these projects, their contribution will grow slowly, and in our view not fully offset the decline in the Lower 48 conventional production. Thus, we look for a slight decline in total supply between 1980 and 1990. The result of these demand and supply trends, we believe, will be a renewal of the excess demand which confronted the gas industry in the early 1970s.

It is important to recognize that this excess demand will tend to occur during the period when much of the industrial boiler and power generation load is fully convertible into alternate fuels and can be quite flexible in its shifting. Thus, we would expect to see increasing interruption of dual-fueled boiler and power generation customers to offset the limited gas supplies. The level of total interruption to be borne by these customers in 1985 could be as much as 3.7 tcf if all new loads actually grow as projected. Over 75 percent of the reductions in deliveries would be to large boiler fuel customers and power generating plants. Regionally, the reductions would be heavily concentrated in markets where boiler fuel and power generation are important.

As the NGPA is currently written, several of the gas categories will be deregulated in 1985. Congress clearly expected that gas markets would be in balance at that time and would permit an orderly transition to deregulation. However, since the price trajectories of regulated gas are so much lower than those of deregulated oil, one now could expect market forces in 1985 to supply a significant gas price correction upon deregulation. This has been termed "flyup" in many discussions. One can picture a price correction for deregulated gas sufficient to bring the average value of all gas to market clearing levels. We call this level "allowable flyup."

It is the existence of a quantity of gas remaining under regulation below market clearing levels--a so-called "roll-in" capacity--which permits flyup to occur. We estimate that in 1987 some 4.4 tcf of gas will remain under regulation. It is in our lower-bound oil price case that gas is priced approximately $2.50 below clearing levels, creating some $11 billion of roll-in capacity. Alaskan gas in 1987 requires $3.7 billion of roll-in in this lower-bound case. In our least unlikely price scenario, the roll-in capacity rises to $24 billion in that year and Alaska requires less than $1 billion.

The relatively small annual volume of totally new reserves being committed after 1985 will be free to select price and contract terms without constraint. One could anticipate that undisciplined bidding for these comparatively small volumes of new supplies in a tight market could lead to quite high individual contract prices from the roll-in effect. There will also be a much larger volume of Section 102 and other gas (committed from 1977 to 1985) under contract which will be free to move to whatever internal limits the contracts themselves dictate. Where these contracts have provided for indefinite pricing provisions, such terms could well be triggered in 1985 and drag up a much larger volume of deregulated gas to higher levels as well. The actual way in which such flyup might occur is dependent both on the nature of the Section 102 gas contracts as well as on the market psychology of the time and its effect on the discipline gas buyers show to 1985 supply contracting.

Flyup is also an individual pipeline--rather than a nationwide--phenomenon. Some purchasing pipelines will clearly have more roll-in capacity; some will have less as contracting develops over the next years.

A further complication is the existence in many contracts of buyer escape clauses which enable the buyer to renegotiate his contracts downwards in the event of market pressures. One thus can envision a "flydown" effect as well, under certain circumstances.

The degree to which flyup will actually occur and absorb some roll-in capacity which could otherwise help to accommodate Alaskan gas is thus extremely difficult to estimate, particularly since much of the gas which will be subject to flyup is not yet under contract. We recognize that the gas industry could negotiate away much of its flexibility to absorb Alaskan gas, particularly in lower oil price cases. However, we sense a growing awareness of the problem among the pipelines, and see some evidence of attempts to address the issue through more careful supply planning. We thus believe it is manageable.

II. THE ROLE OF PRICE

Alaskan natural gas is expected to be delivered to the Lower 48 States in 1987 at a price which will range from $7.70 to $8.94 in constant 1980 dollars. This price range seems high when compared to the present prices of $4.94 for Canadian or Mexican gas at the border, or the $2.81 presently permitted for new (Section 102) gas under the NGPA, let alone the average price of $2.02 for all gas industry supply. But in these days of volatile energy pricing, the critical price relationships are those which will prevail in 1987 when Alaskan gas comes on line, rather than those of today. We believe that the price relationships among Alaskan gas, other gas sources, and alternate fuels will have altered substantially by that time.

Perhaps the single most important element in competitive fuel price formation during the 1980s will be the outlook for international oil prices. Rising prices for OPEC oil supplies have two important effects on oil and gas competition. First, rising oil prices tend to stimulate the demand for gas at the expense of oil--particularly in the price-sensitive dual-fuel market. But since prices of most supplementary supplies, such as LNG or overland imports, will increasingly be tied to international oil price levels, rising oil prices make these sources relatively less attractive by comparison with Alaskan gas. Thus, a rising oil price environment makes Alaskan gas increasingly competitive, not only with oil, but with most other supplementary gas sources as well.

In 1973, at the time of the first oil price shock, interstate natural gas prices in the United States were price-regulated at levels which did not reflect competitive fuel values. Intrastate prices had been held below alternate fuel prices by price competition in a period of surplus intrastate reserves. Imported Canadian gas was priced on a netback basis from the price-regulated U.S. market. After the rapid increase in oil prices in 1973/1974, reserve shortages in the intrastate market caused intrastate prices to break free of interstate pricing and move to alternate fuel parity based on residual fuel oil. The Canadians abandoned the policy of netback pricing to the regulated U.S. market and began tying their prices unilaterally to changes in international oil price levels.

The Canadian precedent of tying export gas prices to international oil prices has spread and become the general practice nearly everywhere. The past two years have seen negotiations between the U.S. and Mexico, the U.S. and Canada, Japan and Abu Dhabi, the Soviet Union and Iran, and both the U.S. and France with Algeria--all over the relationships between oil and gas pricing in international trade. While no uniform formula for linking such prices has yet been developed, it seems nearly certain that future increases in world gas prices will be directly linked to changes in world oil prices.

Since the passage of the NGPA, nearly all U.S. gas supply--intrastate as well as interstate--has been placed under price regulation in which price escalation is independent of changes in international oil prices. We estimate that the price of only about nine percent of U.S. gas supply was affected by oil price changes in 1980. Somewhat less than seven percent of U.S. gas supply in 1980 was from supplementary sources, either oil-based SNG or imported gas, and less than three percent was deregulated conventional production.

But by 1985, with the deregulation of new gas and the growth of supplements, only 27 percent of gas supply will remain fully price-regulated. Supplements will account for 19 percent and deregulated gas for 54 percent of total supply. The role of price-regulated gas declines as it is depleted and as supplements constitute a growing share of the total.

In the 1980 environment, the rapidly rising price for oil made gas competitively attractive. But by 1990, a rapidly increasing price for oil will lead to a rapidly increasing price for gas as well, since much of the gas supply will be price-linked to oil. Gas supply sources which avoid this direct linkage--such as Alaskan gas with its 20-year average price range of $4.22-$5.63--will be relatively favored. In a 1990 environment of escalating world oil prices, Alaskan natural gas with its large capital costs, will increasingly look like a bargain as the facilities are depreciated and costs decline.

The Outlook for Oil and Gas Prices

The favorable market outlook for Alaskan natural gas is heavily influenced by the expected future course of competitive oil and gas prices. Because of the importance of these future price estimates to the conclusions of this study, we have laid our analysis out in some detail in this section.

In this report, we utilize two forecasts of oil prices. One of these --our least unlikely case--is based on the expectation that international oil price formation will operate very much during the 1980s as it has during the 1970s. The dominant feature of recent international oil price development has been a sporadic political or military crisis in the Middle East; this has generated panic buying in the marketplace and a rapid escalation in oil prices. These prices subsequently decline in real terms as the disruption passes and world economic activity reacts to the sharp dislocations in pricing. For our least unlikely case, we have arbitrarily assumed that a disruption will occur in 1984 and the pricing pattern both during and after the disruption will be similar to 1973/1974 and 1979/1980.

For purposes of this analysis, however, we have assumed that such a forecast, with its disruptive price pattern, would not present a credible test of the marketability of Alaskan gas. Therefore, we have utilized instead a "lower-bound" price case which represents the lowest level of prices that we think are plausible over the next decade.

It is this projection--one which assumes that political disruption will have no significant effect on oil prices throughout the decade--which we utilize in this report to test Alaskan gas marketability. The basic crude projection has been adjusted for transportation and other crude oil sources, and then converted into a price series for the refiners' acquisition cost of crude oil. This series has been used in turn to develop both distillate and residual fuel oil prices by region.

Our gas price projections are made individually for the many regulated pricing categories of gas under the NGPA, as well as for the various supplemental gas projects and import volumes. These prices are then modified for transmission costs and for distribution margins to arrive at regional estimates of retail gas prices by type of customer.

The period following new natural gas price deregulation in 1985 poses special analytical problems because of the uncertainties surrounding the price behavior of deregulated gas after that time. Since the middle 1970s, most contracts--interstate and intrastate--have been written with escalation clauses, in some cases indefinite escalation clauses, which continue to increase even though the current price itself may be limited by regulation. In 1985, when deregulation occurs, many of these contracts will move to the levels established by the contract terms. In those cases with indefinite price escalators which will be permitted to operate after 1985, the behavior of buyers and sellers in 1985 in setting new price levels will bring up the value of old contracts as well. This phenomenon of upward price pressure with deregulation in 1985 will finally be defined both by the nature of the contracts written between now and 1985, but also by the marketplace psychology in 1985, particularly as it influences the willingness of suppliers to bid competitively for short supplies. Our analysis suggests that there will be excess gas demand in 1985 from markets that would prefer cheaper gas to more expensive oil. We thus believe that some level of flyup is inevitable. Recent offers by gas pipeline companies as high as $7-$8/mcf for deep Tuscaloosa Trend gas in Louisiana indicate the potential for high prices in the early days of decontrol, while average gas costs remain low.

To illustrate the way in which flyup might operate, we have allowed the price increases for <u>deregulated gas</u> in 1985 to rise to a level high enough to bring <u>average gas prices</u> to estimated clearing levels. We call this "allowable flyup." Because of the disparity between gas and oil price levels at that time, the flyup price increases are comparatively large. Figure II-1 shows our projections of conventional Lower 48 prices (including "allowable flyup"), together with Alaskan gas, all other supplements, the hypothetical clearing price, and the refiners' acquisition cost for crude oil.

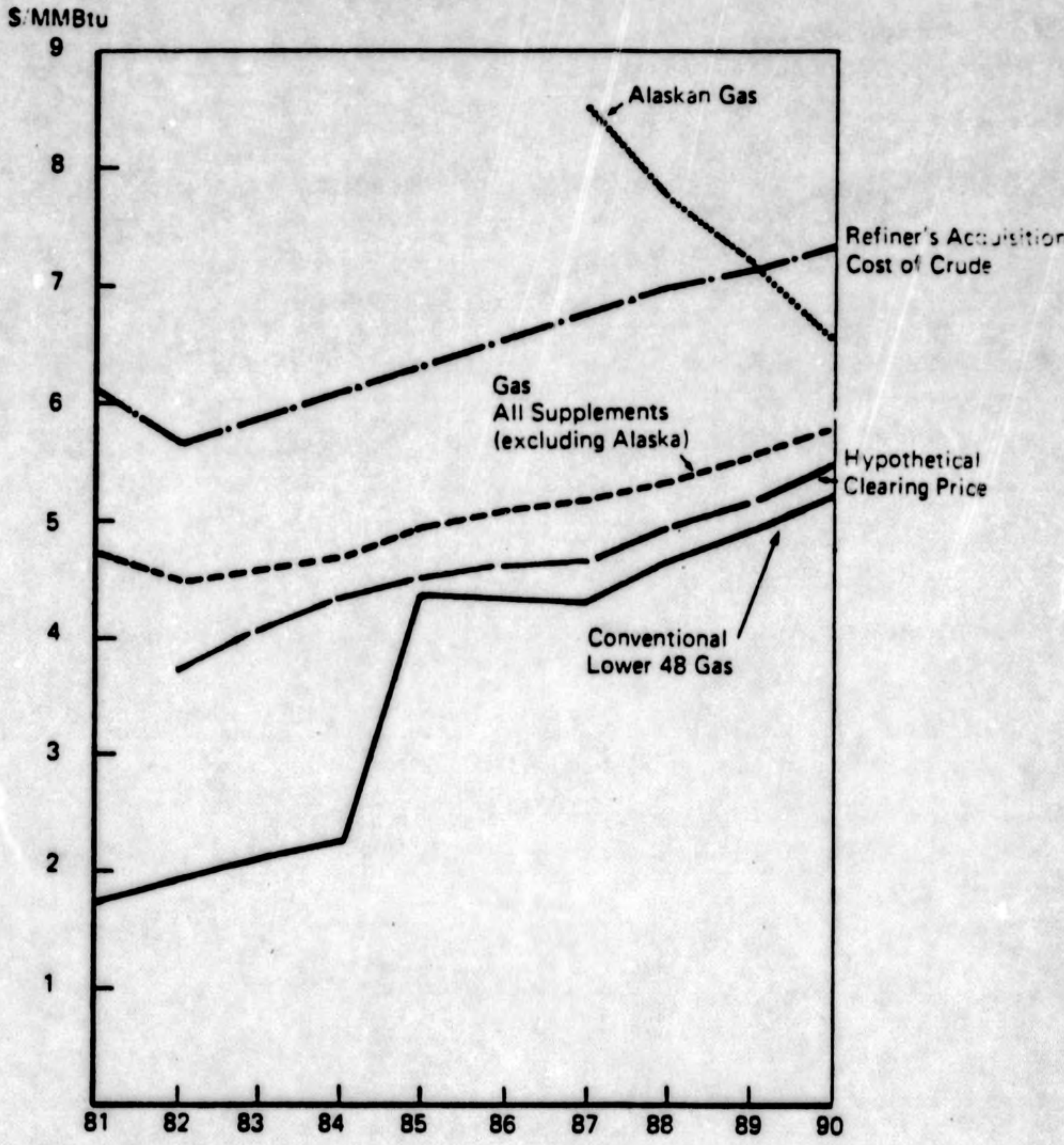
<u>International Oil Markets and OPEC</u>

From 1973 to 1981, prices of international oil to U.S. markets rose at an average rate of nearly 14 percent per year in real terms. This was not

FIGURE II-1

GAS WELLHEAD PRICES COMPARED WITH REFINER'S CRUDE ACQUISITION COST

(1980 Dollars per million Btu)



Source: Jensen Associates, Inc.

a classical steady growth curve, however, since virtually all of the increase was confined to two comparatively short periods--October 1973 to February 1974 during the Arab oil embargo, and again from December 1978 to February 1980 precipitated by the Iranian revolution. There is thus compelling evidence that the dominant force in real price increases over the decade has been the panic buying which accompanied the crisis markets of 1973/1974 and 1978/1980 rather than any orderly price administration by OPEC. OPEC's principal role has been to resist the erosion of real oil prices during the periods between rises.

Both of the sharp price runups occurred when a sudden loss of production within OPEC occurred during periods of strong demand for OPEC oil. The embargo, through its politically mandated production cuts, took roughly 3 MMbpd of OPEC capacity out of service at a time when world economies were booming and demand was approaching physical capacity limits. The Iranian Revolution reduced Iranian production by nearly 5.5 MMbpd at a time when underlying demand was not so strong, but psychological fears of shortage caused unprecedented inventory accumulation worldwide.

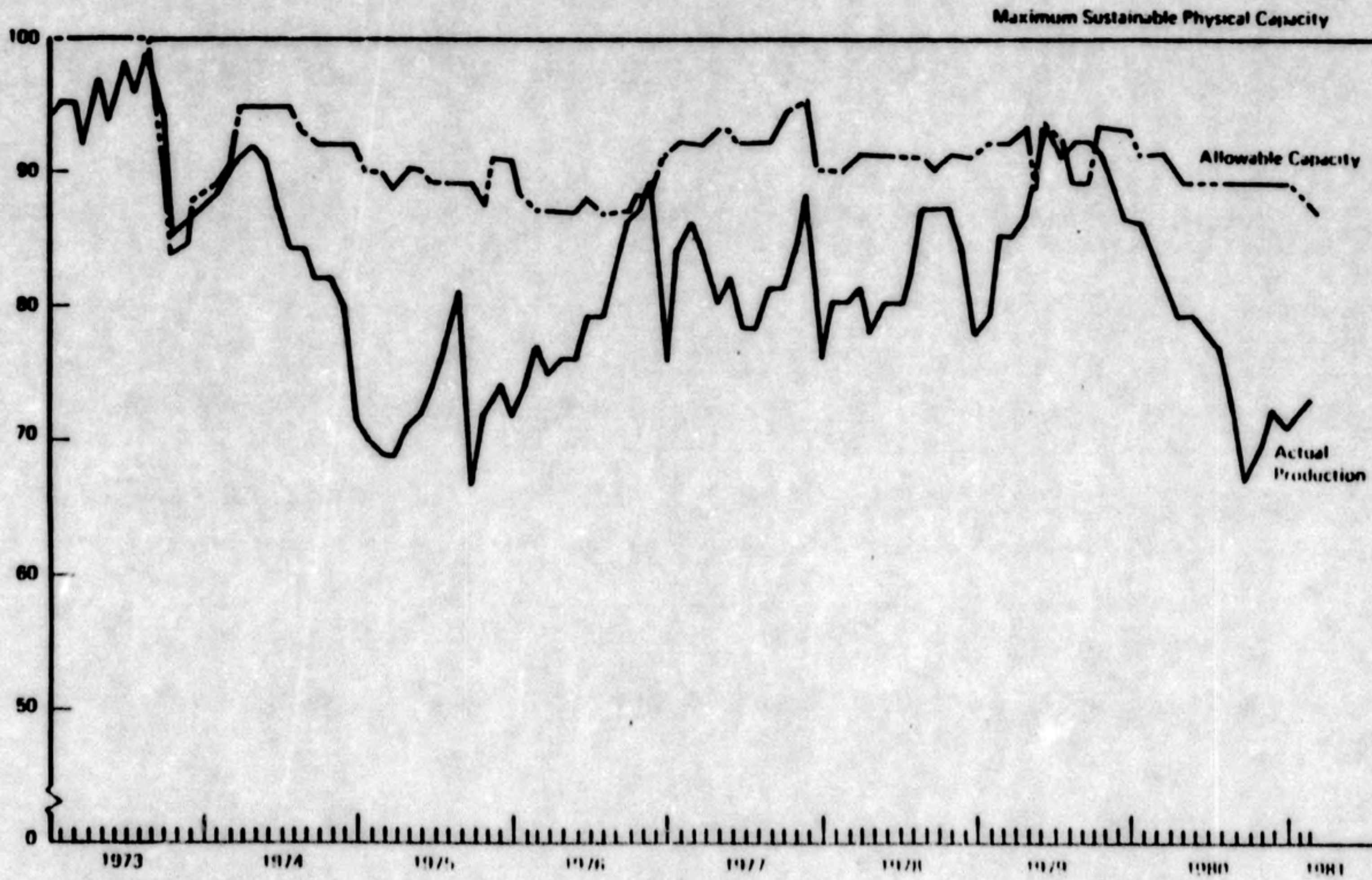
Except for these two periods of market-inspired price behavior, international oil pricing has largely been the result of OPEC price administration decisions within the context of OPEC political debate. Thus, for most of the past eight years, interpretation of the conflicting political pressures within OPEC has been a more important tool for projecting oil prices than the more classic economic analysis of supply and demand has been. This is not to say that supply and demand relationships are not important, but they have served to set the stage on which the price debate has taken place, rather than to establish prices directly.

Figure II-2 shows OPEC production and "allowable capacity" as a percent of maximum sustainable physical capacity within OPEC over the past eight years. In 1973 OPEC physical capacity stood at 32 MMbpd and most projections at the time expected it to rise to the lower to mid 40s by the end of the decade as steady demand for OPEC oil continued to mount. After the takeovers of control of their own oil which accompanied the 1973/1974 period, most OPEC members could not or would not increase capacity. However, since 1973, demand has been significantly less than had been anticipated earlier so the added capacity has been, for the most part, unnecessary. Physical capacity in OPEC peaked in 1976/1977 at 38 MMbpd and has since declined to 34 MMbpd, in part as a result of the loss--perhaps permanently--of a portion of Iranian capacity.

The concept of "allowables" was first developed by Kuwait, which has consistently argued that keeping oil in the ground is a safer way to protect surplus wealth than creating financial assets from higher production and revenue levels. Allowable limits have now been adopted by other surplus countries such as Saudi Arabia and Abu Dhabi. The argument of the surplus countries is that the world should not count on OPEC's delivering more than its allowable capacity even though production in excess of allowables may occasionally be utilized for special purposes. Saudi Arabia, for

FIGURE II-2

ACTUAL AND ALLOWABLE CRUDE OUTPUT AS % OF MAXIMUM SUSTAINABLE PHYSICAL CAPACITY



Source: Jensen Associates, Inc.

example, currently is producing 10.3 MMbpd against an allowable of 8.5 MMbpd as a part of its internal OPEC dispute over price reunification.

As is evident from Figure II-2, demand for OPEC oil was approaching physical limits in 1973 when the embargo sharply reduced OPEC's available production. While the price increases of October 1973 and January 1974 were OPEC-dictated, they were foreshadowed by a spot market which rose to even higher levels as a result of threatened shortages.

Figure II-3 shows the U.S. refiners' acquisition cost of imported crude oil in constant 1980 dollars compared to OPEC production as a percent of allowable capacity. In both the 1973/1974 and 1978/1979 price jumps, OPEC production exceeded allowable capacity. The only other time when that occurred was in the Winter of 1976/1977 when OPEC production reached an all time high of 34 MMbpd. An increase in the Saudi allowable capacity helped to avert a greater nominal price increase at that time.

Many observers--including ourselves--expected another possible upward price spike during the Winter of 1980/1981 with the loss of capacity from the Iraq-Iran war. Indeed, there was a flurry of rising spot activity in October and November which subsequently subsided. In retrospect, it appears that the market had weakened sufficiently so that the panic psychology which dominated 1979 markets was fully dissipated.

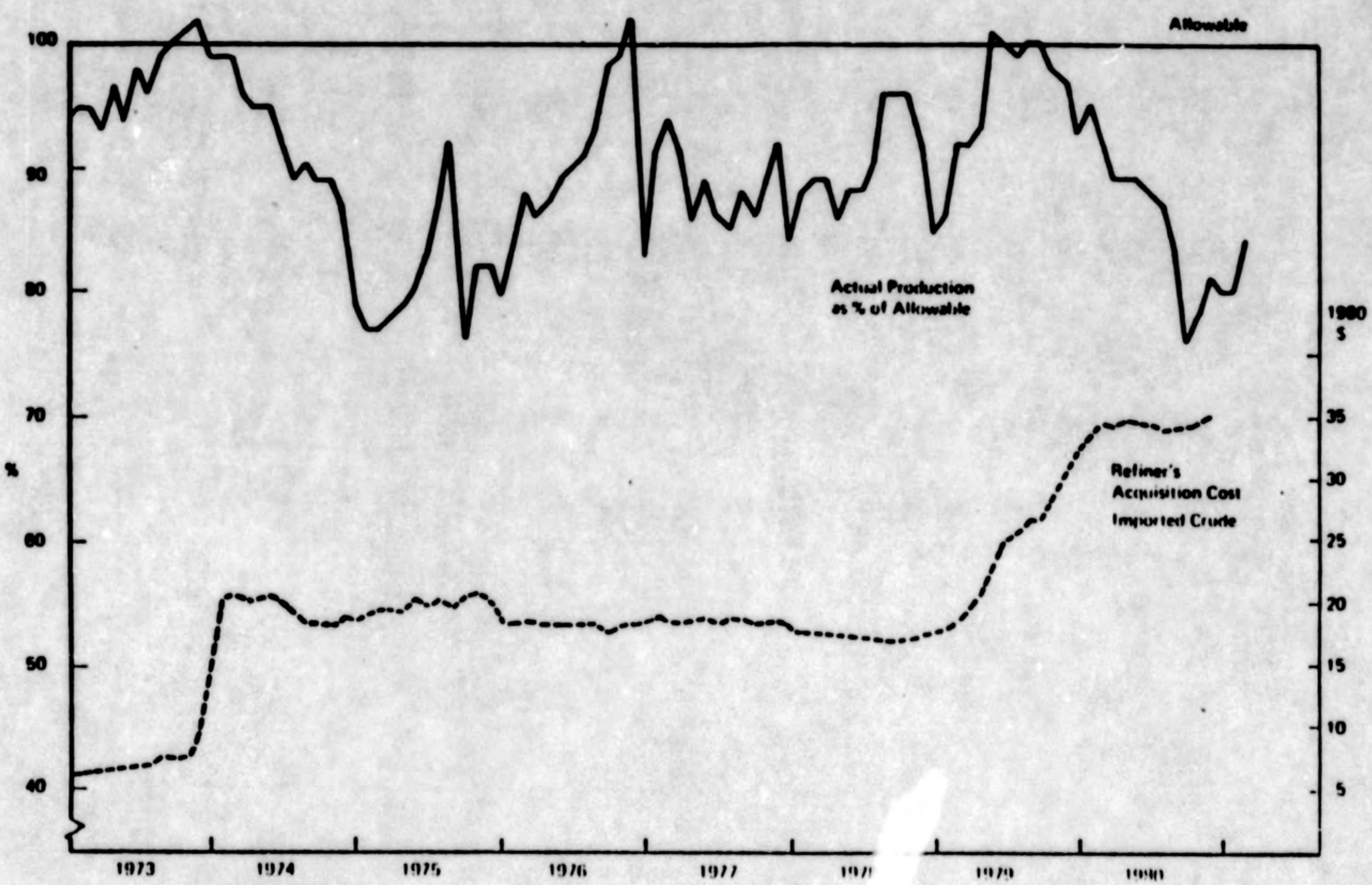
We are now--as of June 1981--in a much softer oil market than most forecasters anticipated. Free world demand for oil may fall to 46-47 MMbpd this year and net demand for OPEC oil could be as low as 23 MMbpd--the lowest level since 1970. This would place the demand on OPEC at about 74 percent of allowable capacity, a level even lower than in the weak market of 1975. The question is naturally being raised as to whether this low a demand represents a new long-term secular trend, and whether the assumption that OPEC can dictate price levels in all but tight and rising markets is still valid. Can OPEC, in fact, hold together and prevent further erosion of prices in a market such as this?

We at Jensen Associates believe that the underlying OPEC structure is not seriously threatened by present market conditions, despite an appearance of internal dissension within the organization. We view the present market downturn as more cyclical than long-term, although major long-term changes in demand are clearly taking place. The world oil surplus results largely from a reduction in energy demand--in part recession influenced--rather than an increase in alternate energy supply above expected levels. If anything, alternate energy supplies have consistently fallen below projected levels throughout the world.

There has been a tendency for OPEC oil to play a swing role in world energy demand. This tends to exaggerate the effect of short-term energy market changes on the demand for imported oil and suggests that a sharp 1981 downturn could be followed by a sharp rebound with improving world economic conditions. In a static world energy supply pattern, where OPEC

FIGURE II-3

CRUDE PRICES VS OPEC CAPACITY OPERATION



Source: Jensen Associates, Inc

oil bore the entire swing in total demand, a downturn of one percent in world energy demand would manifest itself as a four percent downturn in OPEC oil demand. This would result from the fact that oil represents about half of energy supply, and OPEC oil is about half of total oil supply.

While OPEC oil does not fully occupy the swing role--downturns in the steel industry reduce coking coal demand and U.S. natural gas demand has been affected by a sluggish economy--we believe that most of the downturn is indeed concentrated on OPEC. World energy supply is also dynamic, rather than static, so that when previously planned increments of new alternate energy supply exceed the demand for them, they tend to back out imported oil selectively. Thus, we believe much of the present decline in OPEC demand is short-term, rather than long-term.

We expect to see a measure of economic recovery in the OECD by 1982 and anticipate a strengthening of demand on OPEC at that time. Thus, we look for a continuation of OPEC's ability to establish floors on world market prices during soft markets.

During the Spring and early Summer of 1981, the popular and business press has been full of reports of falling oil prices, and frequent suggestions that OPEC may in fact have lost its ability to prevent price erosion in soft markets. While it is clear that spot markets are falling, that some governments are cutting official selling prices, and that prices are declining in nominal as well as real terms, this evidence of price weakness in OPEC is somewhat misleading.

The chaotic markets of 1979 and 1980 led to substantial disorder in OPEC pricing patterns. During the more placid markets between 1974 and 1978, OPEC operated on a "marker crude" system in which the price of the principal Saudi crude--Arab Light--was priced by OPEC agreement and values of all other crudes were based on their quality or transportation differentials relative to Arab Light. The light African crudes from Algeria, Libya and Nigeria, for example, usually enjoyed about a $1.50 per barrel premium over Arab Light based on both their higher quality and their relative nearness to market. Today those market-dictated differentials are perhaps no higher than $2.00 per barrel.

During the turbulent markets of 1979, some OPEC governments were able to command prices which had little market logic since buyers were desperate to have secure supply regardless of price. Some of the African crudes have been officially priced at $41 per barrel--a full $9 per barrel over the official government selling price of Arab Light at $32 and therefore much higher than the normal market differential of $1.50-$2.00. The highly publicized oil price cutting has been concentrated in the abnormally high differentials being asked by the price hawks, rather than in the underlying price structure of the Arab Light marker.

Before the Iranian Revolution, OPEC, with strong Saudi support, established a long-range strategy committee to consider a number of long-term problems facing OPEC. One major focus of the study was a desirable future course for world oil prices. The committee's recommendation was for a gradual but steady increase in real crude prices to replace the stop-start pattern of crude price increases which characterized the 1970s. The committee called for a formula to adjust the price to cover inflation, to adjust for changes in the value of the dollar, and to add a real price increment based on the growth of GNP within the industrialized countries. It has been quite clear that Saudi Arabia has been a major backer of this proposal within OPEC. However, the orderly pricing formula presumes a unified and orderly set of differentials about the marker crude. The 1979 market conditions effectively destroyed the unified OPEC price structure which could serve as a base for the application of the long-range pricing formula.

The Saudi official price for Arab Light has been \$32. Most other OPEC members have adopted a "deemed marker crude" which most commonly is based on the assumption that the marker sells for \$36. "Special market premiums" over and above normal differentials have been adopted by some governments.

The present Saudi policy of producing at 10.3 MMbpd rather than at their 8.5 MMbpd allowable in the face of world oil surpluses seems designed to force market realignment of the hawks' differentials about some orderly marker crude structure.

Until recently we--like many other oil market observers--believed that the Saudis were sufficently committed to the OPEC long-range planning formula that they were prepared to make price concessions on their \$32 in order to reunify the system. Indeed, the Saudis themselves had sold "war relief oil"--a special offering designed to assist those who had lost supply because of the Iraq-Iran war--at a price of \$36. This led many observers to conclude that this was the logical compromise price for a unified marker system.

More recently, however, it appears that the Saudis have become concerned at the extent of the 1981 downturn in OPEC oil demand, questioning whether prices have gotten too high. They now appear to have shifted policies to force compromise nearer their present \$32 official price, despite the ill will which that effort appears to be earning them in some OPEC circles. Some of the widely publicized price cuts by the OPEC members are consistent with the \$36 or a \$34 marker. The \$32 marker is as yet not accepted as a compromise standard.

The Crude Price Projections

Our lower-bound crude oil price projection assumes that the unified price will be based on a real \$32 marker (as of June 1981) which will hold through the end of 1982. With a pickup in world oil demand in 1983, the real price will again start to rise with the long-range planning formula at a rate of about three percent per year. The actual unification may not require that other OPEC members be forced to recognize and accept that \$32 price, since it would be possible for them to save face by freezing at some higher level until the inflation-dictated increase in the nominal marker price rose to an appropriate level.

Our least unlikely case assumes surpluses persist through 1982, as well, and that the formula is applied in 1983. However, it also assumes that some disruptive market event will occur before 1987--we have arbitrarily placed it in 1984--with price behavior during and after the event similar to the 1973/1974 and 1979/1980 disruptions. The least unlikely case, with its disruption, results in an overall real price increase of eight percent per year to 1990. While this is significantly higher than many current oil price projections, it is considerably lower than the 14 percent per year actual real price increase from 1973 to 1981. The increase in the lower-bound case is 2.5 percent per year over the same period. These projections are shown in Figure II-4.

Oil Prices for the U.S.A.

We have forecasted a basic crude oil price in the Arabian Gulf, f.o.b. the export terminal. Such crude has to be transported to the U.S.; it will form only part of a selection of crudes that American refiners import; and the oil with which Alaskan gas competes in regional final markets will be refined products, mainly No. 2 oil and No. 6 oil.

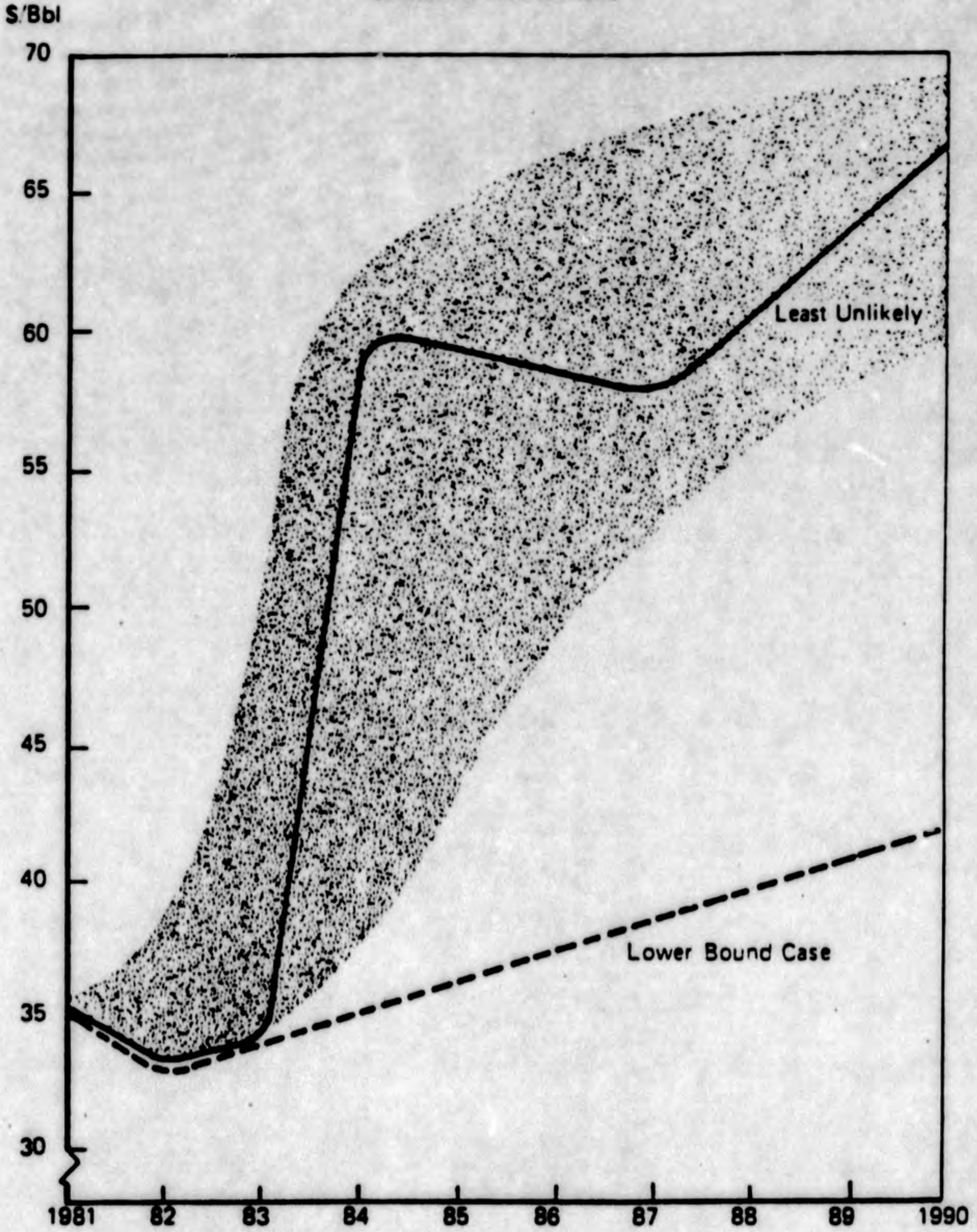
Even while a surplus of capacity overhangs the world tanker market, there continue to be quite sharp fluctuations in freight rates--partly because the surplus is not uniform for all sizes of vessels, and partly because unpredictable demands for tonnage (e.g. recently for Very Large Crude Carriers and Ultra Large Crude Carriers for use as floating storage) often occur. More generally, the shift of a growing proportion of crude oil exports from the integrated trading channels of the international major oil companies into non-integrated trading by OPEC national companies with smaller scale private buyers or governmental buyers downstream has reduced logistic efficiency in the whole international employment of tankers. Slow steaming to reduce fuel costs, again, involves more tankers for any given ton mileage of crude oil movement.

Those factors have raised oil transport costs during the last two years. High prices for oil fuels will continue to tilt the economics of tanker operation. Logistic inefficiencies arising from less integration in world oil trading may also persist. On the other hand, the deepening and widening of the Suez Canal that has now been completed, and the possibility of further increases in its capacity to handle large tankers by about 1985, point to some reduction in the average distances that oil will have to move by sea to markets. And recent forecasts by tanker experts that freight rates may resume an upward trend (as distinct from short-term fluctuations) by about 1983-1985 have generally assumed rather higher growth rates in the world economy for this decade than most analysts now seem inclined to count upon.

FIGURE II-4

PROJECTIONS OF THE DELIVERED PRICE OF OPEC'S MARKER CRUDE

(Constant 1980 Dollars)



Source: Jensen Associates, Inc.

Detailed predictions of tanker employment and freight rates thus remain as complex as ever. But for the projection of landed prices for crude, it has become less important. Freight costs now represent such a small proportion of c.i.f. prices that one's assumptions about the changes in them make little difference to the projections we have made of crude prices f.o.b. Arbitrarily, we are assuming that average tanker freight costs from the Arabian Gulf to the Texas Gulf remain constant in real terms until 1985, and then rise five percent in real terms annually to 1990. But freight is now so small in comparison with the f.o.b. price that our resultant projections of c.i.f. crude prices (Figure II-4) differ hardly at all in slope from the f.o.b. price trajectories we have already set out. (An alternative assumption raising this real freight cost increase to 10 percent annually, or starting it earlier, would make a difference of cents rather than dollars per barrel.)

Product Prices

Natural gas competes with distillate fuel oil in residential, some commercial, and high-value industrial markets. It is most likely to compete with residual fuel oil in industrial boiler fuel and power generation markets. Since the higher-valued, distillate-competitive markets tend to be protected from erosion by both price and priority curtailment status, it is residual fuel which incremental gas supplies most tend to displace.

We have estimated future refinery margins both for distillate and the several sulfur grades of residual fuel oil in making our regional analyses of interfuel competition. Typically, high-sulfur residual fuel oil sells below the cost of crude oil in the United States, while distillate fuel oil carries significant refining margin premiums. These product differentials tend to be volatile, depending on market conditions, and variations can be especially severe in the case of high-sulfur fuel oil in sloppy markets. Nonetheless, total margins between distillate and high-sulfur residual fuel oil in the U.S. tended to average out in the $3.00-4.00/bbl range during much of 1976 and 1977. From late 1978 through 1979, margins blew apart (rising to above $10.88/bbl at one point) as the worldwide problem of adapting to market pressures for lighter, sweeter product mixes came into conflict with the trend toward greater availability of heavier, higher-sulfur crudes. With the worldwide recession and product surpluses more widespread, margins have again collapsed closer to traditional levels.

In our estimates, we expect the tendency will be for wider, rather than the traditionally narrower, product price spreads as the growing need for deeper cracking, coking and hydrogen processing by refiners greatly increases refining complexity and costs. Our margin projections reflect these judgments and are incorporated in our regional interfuel competition analysis.

III. FORECAST OF LOWER 48 STATES GAS SUPPLY

Summary Forecast

An important part of analyzing the marketability of Alaskan North Slope natural gas is the overall gas supply forecast for the Lower 48 States (L48) against which gas demands can be compared. The Jensen Associates' forecast of gas availability to the L48 during the period 1980-1990 is provided as Table III-1. It includes both conventional L48 natural gas production and supplemental sources.

Overall, we expect supply to the L48 to decline from 20.5 tcf in 1980 to about 18.5 tcf in 1990, or by 10 percent during the decade. The net loss of 2.0 tcf results from an expected 5.1 tcf drop in conventional production being partially offset by a 3.1 tcf increase in annual supplemental supplies available by 1990. The supplemental supplies forecast includes unconventional production from low-permeability reservoirs, North Slope gas, Canadian and Mexican pipeline imports, LNG imports and high-Btu synthetic gas manufactured from light liquid hydrocarbons and coal.

Lower 48 States Production

Natural gas reserves and production statistics of the American Gas Association (AGA) show that conventional L48 production rates for natural gas peaked at 22.5 tcf in 1973, then fell annually through 1978 to a level of 19.1 tcf. In 1979, this trend was reversed as production rose to 19.7 tcf, despite a continuing decline in proved reserves which started in 1969. The year 1979 also showed some improvement in L48 reserve additions--reaching nearly 14 tcf. This was considerably better than the 9.8 tcf annual average additions for the 1970s. Table III-2 summarizes natural gas reserves and production figures for the period 1966-1979. Figure III-1 highlights the erosion of the proved reserves base which has occurred as production annually exceeded reserve additions between 1968 and 1979.

Although the AGA no longer develops or publishes gas reserves and production estimates, preliminary figures from the U.S. Department of Energy indicate that L48 production will be down by 0.3 tcf in 1980 from 1979, or at a level of 19.4 tcf on the AGA scale.

Despite this recent slowing in the decline of L48 gas production, we believe that the pace will quicken again during the 1980s. We expect average annual natural gas reserve additions for the L48 will remain substantially below production levels and that, at some point, production rates as a percent of proved reserves will peak, causing production to fall more rapidly thereafter. In recent years, production has been held above 19 tcf per year by steady increases in the rate-of-take from remaining reserves. This has occurred as a result of increased emphasis on in-fill and other relatively low-risk developmental drilling activity. This type of drilling

TABLE III-1

LOWER 48 STATES TOTAL GAS SUPPLY FORECAST

1980 - 1990

(Trillion cubic feet)

Source	1980[a]	1985	1990
Conventional Production	19.4	16.1	14.3
Unconventional Production	0	0.1	0.3
Alaskan Gas	0	0	0.7
Canadian Imports	0.8	1.6	1.4
Mexican Imports	0.1	0.4	0.7
LNG Imports	0.1	0.5	0.7
SNG - Oil Feed	0.1	0.1-0.4	0.1-0.4
- Coal Feed[b]	0	nil	0.2
Total Supply	20.5	18.8-19.1	18.4-18.7

[a] Preliminary.

[b] Excludes low and medium Btu gas.

Source: Jensen Associates, Inc.

TABLE III-2

NATURAL GAS PROVED RESERVES AND PRODUCTION

LOWER 48 STATES

1966-1979

(Trillion cubic feet)

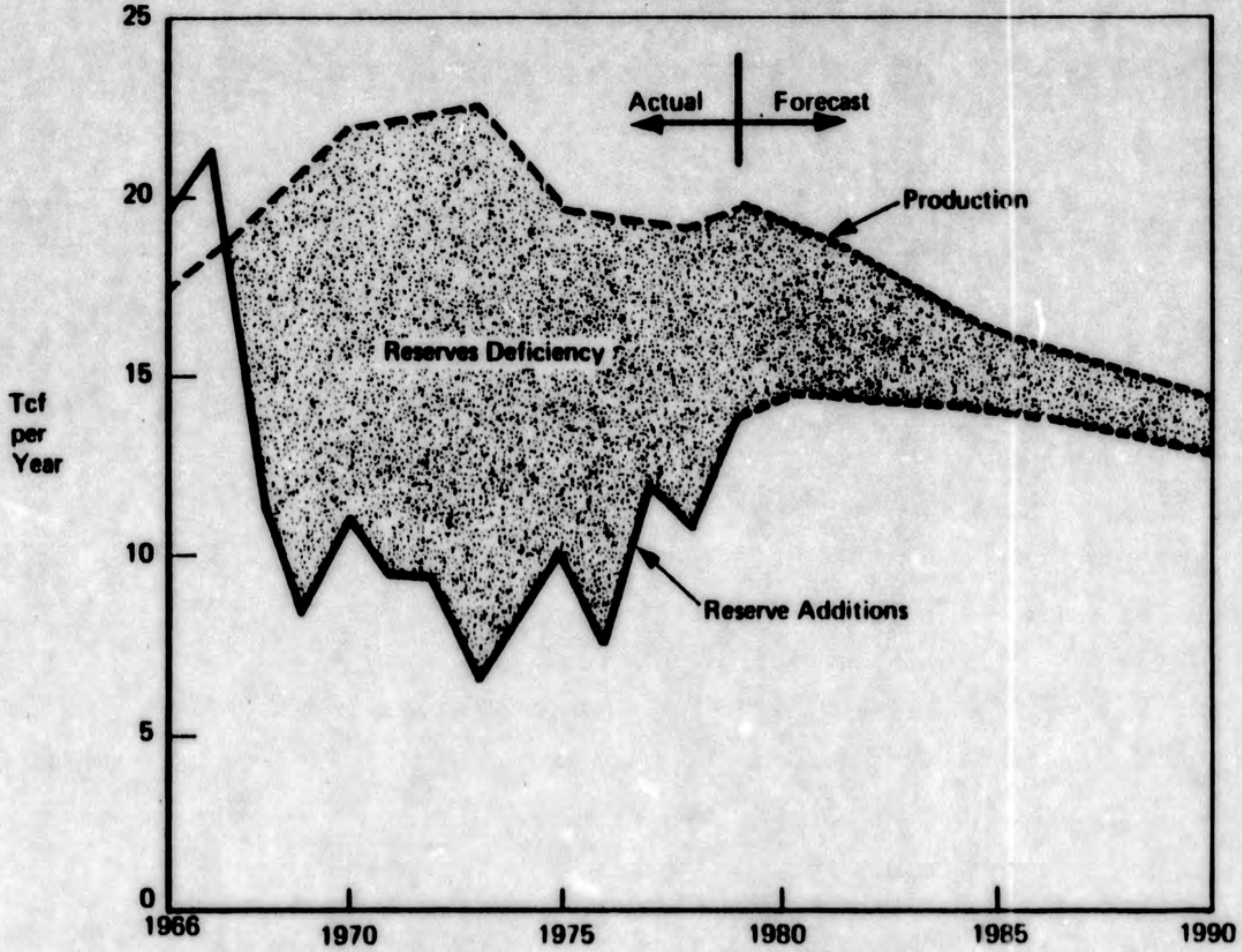
Year	Year-end Proved Reserves	Annual Production	Annual Additions to Proved Reserves	Annual Decline in Proved Reserves*
1966	286.39	17.48	19.25	(1.91)
1967	289.27	18.36	21.09	(2.88)
1968	282.10	19.33	12.04	7.17
1969	269.91	20.64	8.34	12.19
1970	259.62	21.82	11.12	10.29
1971	247.44	21.92	9.44	12.18
1972	234.63	22.37	9.40	12.81
1973	218.31	22.47	6.51	16.32
1974	205.27	21.17	8.31	13.04
1975	196.15	19.56	10.14	9.12
1976	184.10	19.32	7.45	12.05
1977	177.05	19.26	11.76	7.05
1978	168.69	19.10	10.59	8.36
1979	162.98	19.69	13.73	5.71

* Includes changes in volume of gas in underground storage.

Source: Jensen Associates, Inc.
American Gas Association, American Petroleum Institute, "Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the U.S. and Canada"

FIGURE III-1

NATURAL GAS PRODUCTION AND RESERVE ADDITIONS
LOWER 48 STATES 1966-1990
(trillion cubic feet per year)



Sources: Jensen Associates, Inc.
American Gas Association

was stimulated by the large increases in real prices for interstate gas made available in 1976 by FPC Opinions 770 and 770-A.

The relationship between natural gas reserves and production rates, expressed as a reserves-to-producton (R/P) ratio for the years 1966-1979, is shown in Table III-3. After appearing to flatten out at a value of about 10 in the mid 1970s, the R/P ratio continued to fall through 1979. In 1977 when the R/P ratio first dropped below 10, there was a significant increase in the developmental gas well share of total gas wells completed and this increased emphasis on developmental wells has been maintained through 1980 as shown in Table III-4. The higher gas prices which we believe caused this jump in developmental drilling activity can be seen in Table III-5. In 1976, FPC Opinions 770 and 770-A increased the National Rate by 91 cents per mcf for wells drilled after January 1, 1975. The effects these higher prices for gas from new wells had on average wellhead prices are shown in Table III-6, in both current dollars and constant 1980 dollars.

Our gas production forecast is based on analyses of historic trends in both proved reserve additions and production from proved reserves. For reserve additions, this means that we evaluate drilling activity in the major gas-producing areas of the country. We analyze those market forces which have affected the level of gas and oil well drilling and then forecast a level of activity for the 1980-1990 period. Reserve additions, however, do not automatically flow from additional drilling. Some measure of the success of drilling must be applied. Past finding rates (the amount of gas found per foot of well drilled) are studied and projected. When finding rates for a given period are combined with forecast drilling, the product is an estimate of future reserve additions.

American Petroleum Institute (API) drilling data show that gas well drilling activity has been increasing each year since 1971. The most dramatic increase occurred in 1977 when footage exceeded the previous year by over 12 million feet. Table III-7 shows both gas and oil well drilling statistics for the 1966-1980 period. Examination of the figures in Table III-7 shows that although healthy gas well footage increases have continued through the period, there has been a definite decrease in the rate of growth in absolute and percentage terms since 1977. In 1978 and 1979, this slackening may have been caused by drilling activity having caught up with the available rigs, manpower, and other supporting systems necessary for a major drilling increase. However, by 1980, it appears that lead times for a buildup have been met as evidenced by the recordbreaking increases in gas plus oil well footages.

From Table III-7 and Figure III-2, it can be seen that in 1980 oil well drilling had taken preference over gas. Oil well footage climbed 30 million feet in 1980 versus seven million feet for gas. In all but two other years during the 1970s, gas well footage increases have exceeded oil well footage increases. The attractiveness of rising oil prices and the promise of crude oil price deregulation in 1981 had cut deeply into the gas

TABLE III-3

NATURAL GAS RESERVES/PRODUCTION RATIOS*

LOWER 48 STATES

1966-1979

Year	R/P
1966	16.3
1967	15.6
1968	15.0
1969	13.7
1970	12.4
1971	11.8
1972	11.1
1973	10.4
1974	10.3
1975	10.5
1976	10.2
1977	9.6
1978	9.3
1979	8.6

$* = \frac{\text{Previous Year Reserves}}{\text{Current Year Production}}$

Source: Jensen Associates, Inc.
American Gas Association/American Petroleum Institute, "Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the U.S. and Canada"

TABLE III-4

GAS WELL COMPLETIONS BY TYPES
LOWER 48 STATES
1967-1980

Year	Gas Wells Completed	Percent of Gas Completions: Developmental	Exploratory	Wildcat
1967	3,655	85.5	14.5	5.1
1968	3,449	85.9	14.1	3.7
1969	4,072	84.9	15.1	5.7
1970	3,835	87.5	12.5	4.8
1971	3,829	88.6	11.4	5.3
1972	4,926	87.8	12.2	5.5
1973	6,382	85.9	14.1	6.5
1974	7,236	83.5	16.5	6.2
1975	7,576	84.6	15.4	5.9
1976	9,084	84.6	15.4	6.0
1977	11,374	87.0	13.0	4.6
1978	13,060	87.7	12.3	4.1
1979	14,677	87.9	12.1	4.6
1980	15,727	87.5	12.5	4.4

Source: Jensen Associates, Inc.
American Petroleum Institute, "Quarterly Review of Drilling Statistics"

TABLE III-5

CEILING PRICES FOR "NEW" VINTAGE NATURAL GAS[a]
(Current dollars)

Year		Ceiling Price
1970	Hugoton-Anadarko Area (FPC Opinion 568)	19.0¢-20.5¢/mcf
1971	Southern Lousiana Area (FPC Opinion 598)	26¢/mcf
1973	Permian Basin Area (FPC Opinion 662)	35¢/mcf
1974	National Rate (FPC Opinion 699)	42¢/mcf (+ 1¢/annum)
1974	National Rate (FPC Opinion 699-H)	50¢/mcf (+ 1¢/annum)
1976	National Rate (FPC Opinions 770, 770-A)	$1.42/mcf (+ 1¢/quarter)
1978 (December)	Natural Gas Policy Act	$1.97/mcf[b] Section 103 gas $2.08/mcf[b] Section 102 gas
1981 (March)	Natural Gas Policy Act	$2.41/mcf[b] Section 103 gas $2.73/mcf[b] Section 102 gas

[a] The definition of "new" is not uniform, and at times depends upon contract date, well commencement date, and other criteria.

[b] Includes escalation adjustments to the indicated month.

Source: Jensen Associates, Inc.

TABLE III-6

AVERAGE WELLHEAD PRICE FOR NATURAL GAS
UNITED STATES
1966-1980
(Dollars/mcf)

Year	Current Dollars	1980 Dollars
1966	0.157	0.36
1967	0.160	0.36
1968	0.164	0.35
1969	0.167	0.34
1970	0.171	0.33
1971	0.182	0.34
1972	0.186	0.33
1973	0.216	0.36
1974	0.304	0.46
1975	0.445	0.62
1976	0.580	0.77
1977	0.790	0.99
1978	0.905	1.06
1979	1.144	1.25
1980	1.47 estimated	1.47

Source: Jensen Associates, Inc.
Department of Energy, "Monthly Energy Review"

TABLE III-7

GAS AND OIL WELL COMPLETION FOOTAGE
LOWER 48 STATES
1966-1980
(Million feet)

	Gas Well Completions			Oil Well Completions			Gas Share of
Year	Footage	Annual Increase	% Increase	Footage	Annual Increase	% Increase	Completion Footage
1966	25.91	--	--	67.07	--	--	27.9%
1967	21.53	(4.38)	(16.90%)	58.24	(9.10)	(13.51%)	27.0%
1968	20.67	(0.86)	(3.99%)	58.67	0.43	0.73%	26.1%
1969	24.06	3.39	16.40%	61.13	2.46	4.19%	28.2%
1970	22.85	(1.21)	(5.03%)	56.39	(4.74)	7.75%	28.8%
1971	22.61	(0.24)	(1.05%)	48.27	(8.12)	(14.40%)	31.9%
1972	26.75	4.14	18.31%	48.41	0.14	--	35.6%
1973	35.59	8.84	33.05%	44.43	(3.98)	(8.22%)	44.5%
1974	38.98	3.39	9.53%	50.01	5.58	12.56%	43.8%
1975	41.90	2.92	7.49%	64.09	14.08	28.15%	39.5%
1976	47.49	5.59	13.34%	66.20	2.11	3.29%	41.8%
1977	59.51	12.02	25.31%	74.85	8.65	13.07%	44.3%
1978	70.18	10.67	17.93%	72.06	(2.79)	(3.73%)	49.3%
1979	77.72	7.54	10.74%	78.15	6.09	8.45%	49.9%
1980	85.03	7.31	8.41%	108.37	30.22	38.67%	44.0%

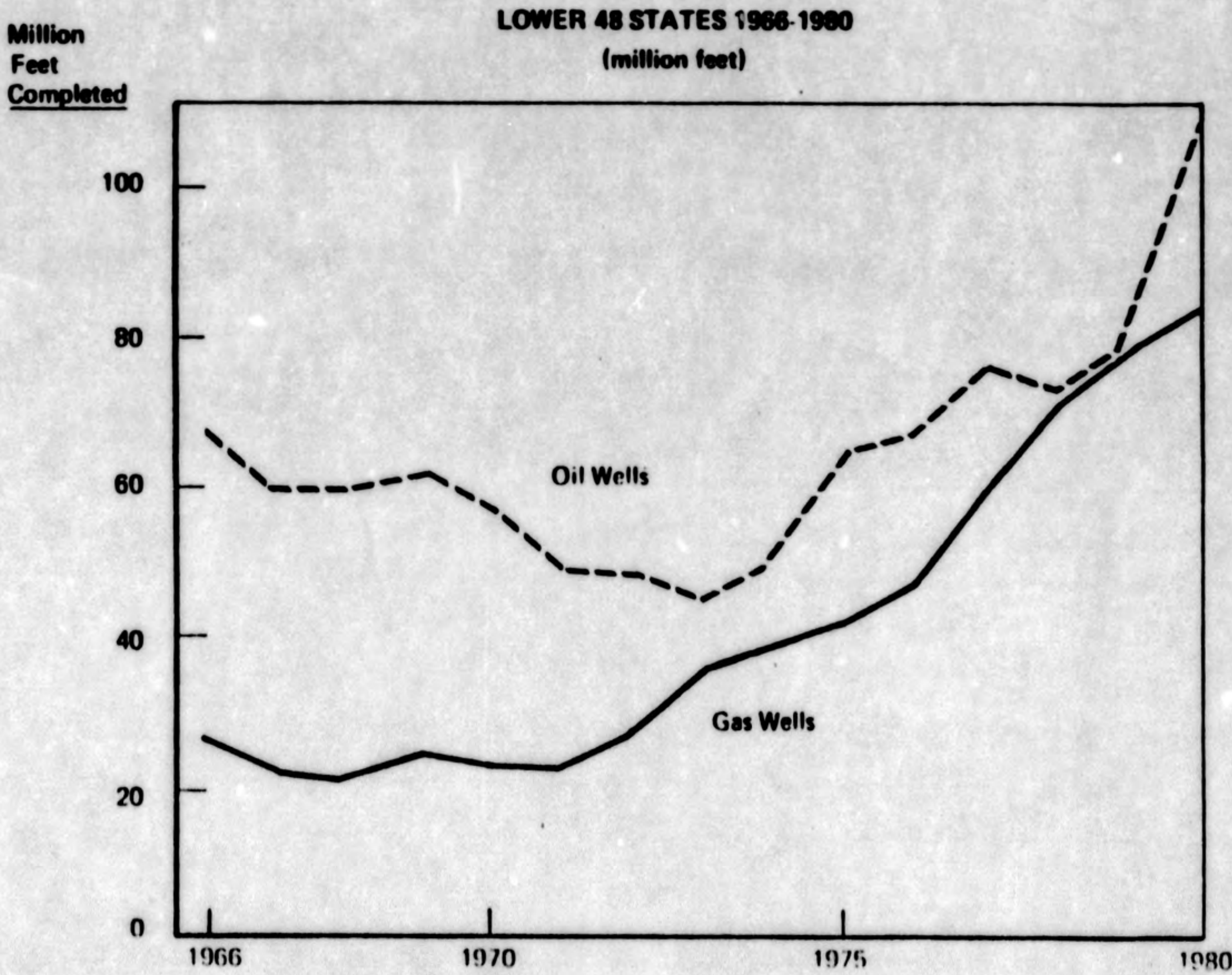
Source: Jensen Associates, Inc.
American Petroleum Institute, "Quarterly Review of Drilling Statistics"

FIGURE III-2

GAS AND OIL WELL COMPLETION FOOTAGE

LOWER 48 STATES 1966-1980

(million feet)



Source: Jensen Associates, Inc.
American Gas Association

share of drilling activity in 1980. API reports that through March 1981, oil well completions are running 35 percent ahead of the same period in 1980, while gas well completions are five percent behind last year's rate, indicating even further drilling preferences for oil over gas may be occurring.

Because of the significantly higher real prices available for many types of regulated gas and the promise of deregulation in 1985, we believe gas well drilling will continue to increase, but at a slower rate, into the late 1980s before leveling off at a plateau nearly 45 percent above the 1979 pace. Thus, we expect the NGPA price incentives to cause a continuation of the gas well drilling surge which began in 1976 as a result of higher real prices made available for interstate gas by the National Rates of the Federal Power Commission. Increases in oil well drilling should support associated/dissolved gas production approximating 10 percent of the gas volume available from gas wells.

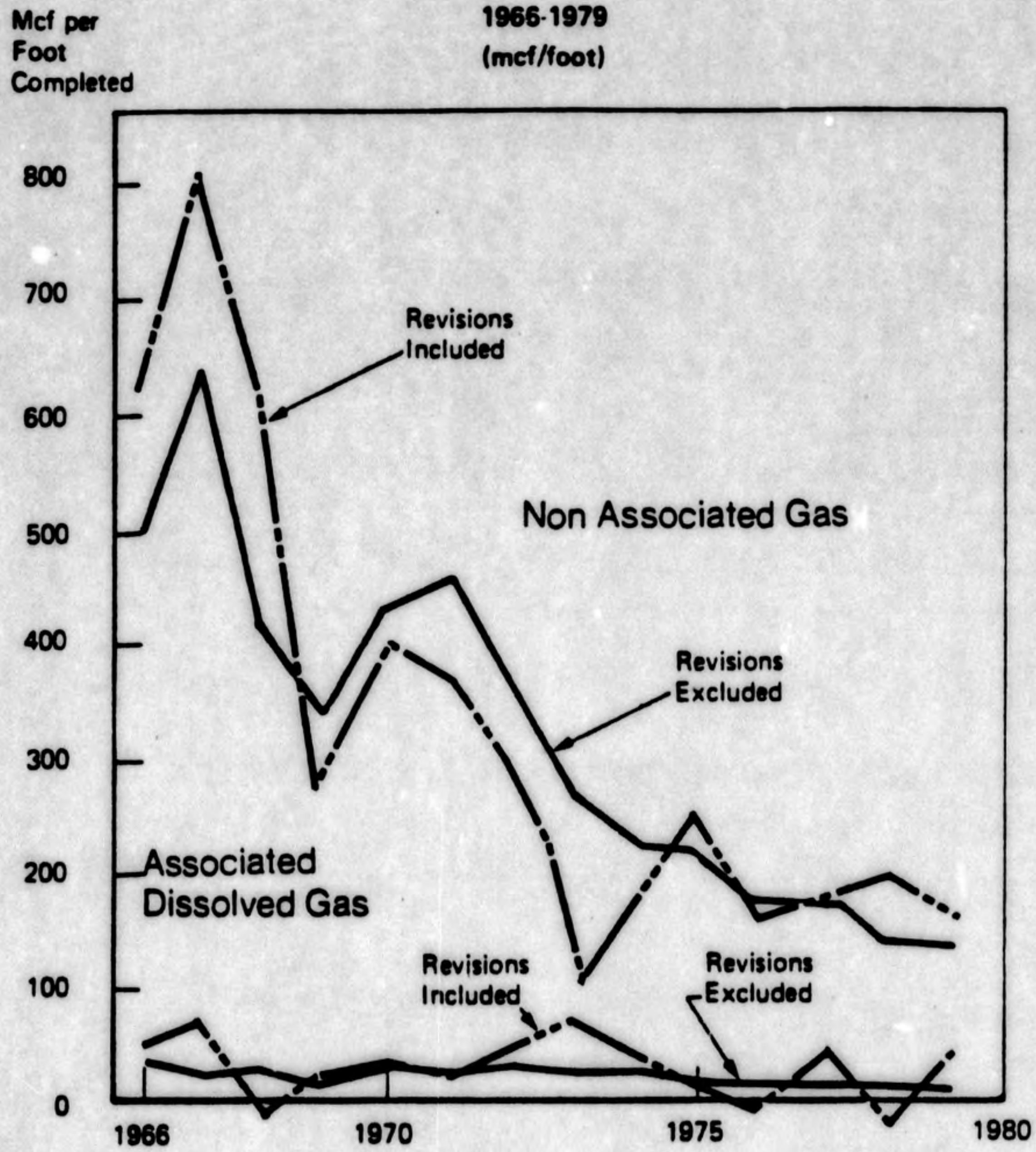
We expect a continuation of the long declines in gas finding rates from gas and oil well drilling. Figure III-3 presents actual finding rates for non-associated and associated/dissolved gas for 1966 through 1979. Units are in mcf of annual gas reserve additions per foot drilled as completed gas wells. Separate rates are shown for cases with annual reserve revisions included and excluded. Both cases show a rapid fall in finding rates for non-associated gas through the early 1970s, moderating to a more gradual decline in recent years. The cause of this trend change is the higher real prices available for gas, which tend to push more previously marginal wells into the commercial category.

Statistics for 1980 show that an increasing share of gas well drilling has gone to exploratory wells where risks are higher, but chances of major discoveries are improved. This, plus any increase in the availability of Federal lands for exploration, could also be helpful in improving finding rates. Finding rates for associated/dissolved gas from oil wells are also expected to continue their more gradual decline through 1990 and beyond.

We forecast non-associated gas finding rates to decline from 150 mcf per foot drilled to 103 mcf between 1980 and 1990. Gas well drilling rates are expected to increase from about 85 million feet in 1980 to 112 million by the late 1980s. The product of these two factors results in non-associated gas reserve additions of 12.8 tcf in 1980, dropping to 11.5 tcf by 1990. Separately, associated/dissolved reserve additions increase from 1.1 to 1.2 tcf during the 1980s. Thus, total gas additions are forecast at 13.9 tcf in 1980, and gradually fall to 12.7 tcf by 1990. These reserve addition levels are well below the production rates of 19 to 20 tcf per year experienced in the late 1970s. A continuing decline in proved reserves will result if production rates remain higher than future reserve additions.

The present administration is more likely to push for accelerated Federal leasing programs--particularly offshore--than was the Carter

FIGURE III-3
NATURAL GAS FINDING RATES
LOWER 48 STATES
1966-1979
(mcf/foot)



Source: Jensen Associates, Inc.
American Gas Association/American Petroleum Institute, "Reserve of Crude Oil, Natural Gas Liquids and Natural Gas in the U.S. and Canada"
American Petroleum Institute, "Quarterly Review of Drilling Statistics"

Administration. Much has been said about the positive effects on discovery rates, particularly for oil, which such an accelerated program could provide. It is important to recognize, however, that the potential positive effect on gas during the 1980s is likely to be much less than for oil. The relatively higher costs of gas pipeline transportation with its necessary emphasis on scale economies means that gas finds in new offshore areas will tend to be commercial only if they are large and/or relatively near existing transport systems. The limited near-term commercial prospects of the small East Coast Baltimore Canyon gas discoveries, or the unlikely early commercial utilization of gas discoveries in offshore Alaskan waters, illustrate the likely slower commercialization of offshore gas than oil. We do not see accelerated leasing as having a major impact on conventional gas supply during this decade.

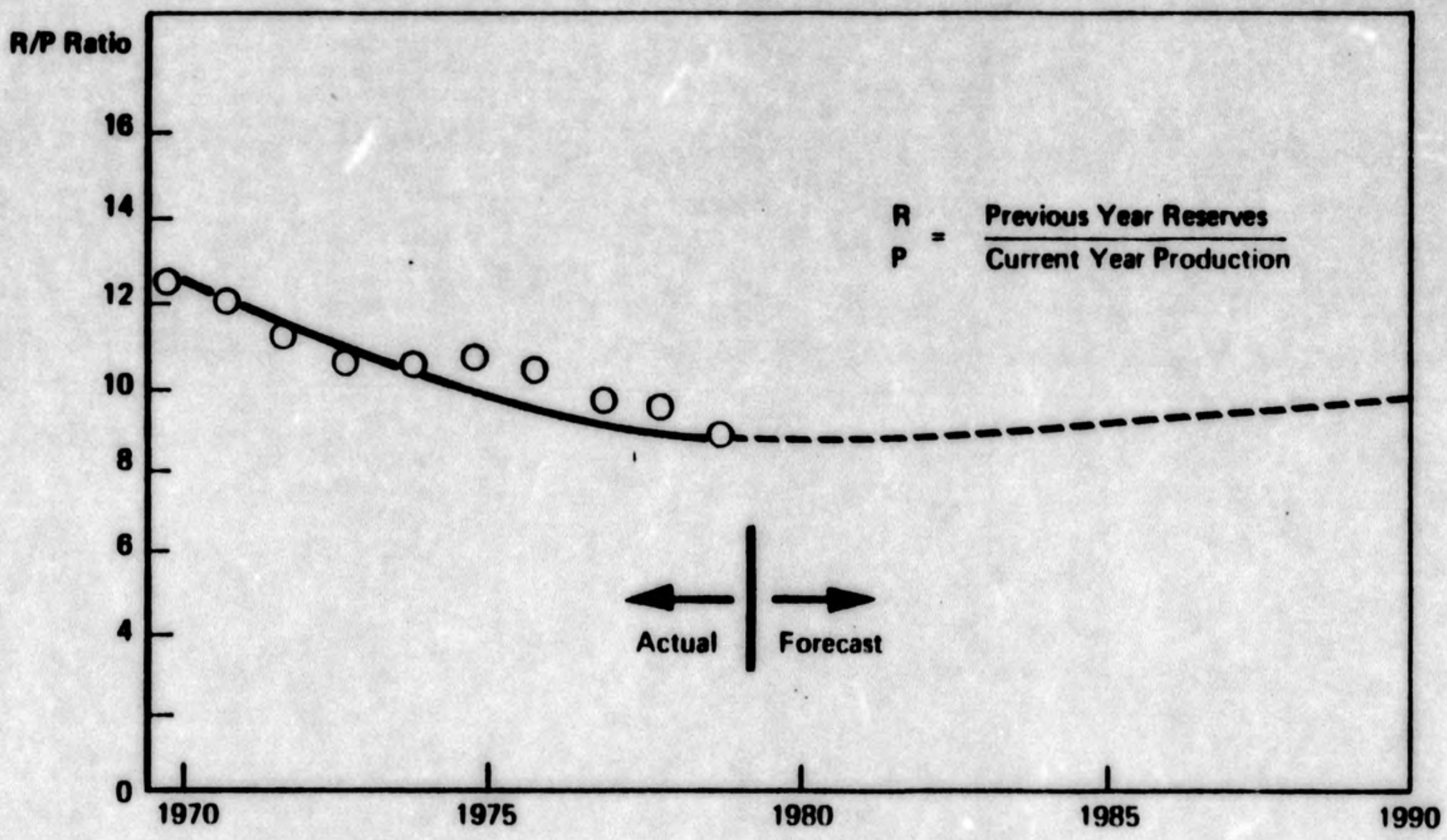
As stated earlier, gas production would have fallen more rapidly in recent years as proved reserves plunged, if the percentage of reserves taken as production each year had not been increasing. Increasing production rates relative to proved reserves generates a falling R/P ratio. Table III-3 provides an historic series of R/P ratios for L48 natural gas, using the annual year-end AGA reserves estimate and the following year's annual production rate. With the exception of a small increase in 1975, the R/P ratio has declined steadily throughout the 1970s. We believe this decline in the R/P ratio is near an end, as explained below.

So long as annual reserve additions are less than annual production rates, the average age of L48 gas reservoirs is increasing. Since pressure decline reservoirs are typically capable of delivering a smaller percentage of remaining reserves each year, older reservoirs tend to increase the average R/P ratio. At some point in time, a minimum R/P ratio (maximum average depletion rate) for all reservoirs must be reached. Its level and timing will depend upon economic and technological factors that control field development. Increasing reservoir age will eventually cause the R/P ratio to rise again as production rates decline relative to remaining reserves. Changes in these observed relationships between reserves and production are expected to be very gradual due to the inertia of more than 160,000 producing gas wells in the Lower 48 States.

We believe that the combined effects of increasing average age of reservoirs, slower growth in gas well drilling, probable decreasing emphasis on developmental drilling, increasing interest in tight gas sands, and extended gas well life provided by higher real prices will prevent the L48 R/P ratio from falling below 8.4 in the near term and cause the R/P ratio to increase very slowly in later years, as shown in Figure III-4. If the R/P ratio should move to lower levels as a result of near-term increases in production above our forecasts, the L48 will experience a more rapid, proved-reserves drawdown (for a given amount of reserve additions) and, consequently, in later years, production rates will drop to levels lower than we have forecast.

FIGURE III-4

NATURAL GAS RESERVES/PRODUCTION RATIO
LOWER 48 STATES



Source: Jensen Associates, Inc.

Examples which support our assumption that the past trend of falling R/P ratios will be reversed are found in two of the more prolific new gas plays in the Lower 48--the deep Tuscaloosa Trend and the Rocky Mountain Overthrust Belt. Both are expected to have R/P ratios considerably higher than the national average figure. In both areas, field development and/or production facility investment are too costly to justify close spacing of wells and high rates-of-take. Low permeabilities are an additional factor in the Overthrust Belt area. This means that more reserves will have to be proved up to obtain a given production rate than is currently necessary in the balance of the Lower 48.

Using the methodology and projections described above, we have forecast gas supply from Lower 48 conventional production to decline from the 1979 level of 19.7 tcf to 16.1 tcf in 1985 and 14.3 tcf in 1990. These figures are nearly identical to the National Research Council's Enhanced Supply scenario published in 1979[1] (after adjusting for inclusion of Alaskan gas by NRC) and are nearly six percent lower than the Department of Energy National Energy Plan II forecast which is endorsed by the American Gas Association. Our forecasts are 1.0 tcf higher than the Middle Oil Price Scenario (Medium Geology) supply case published in the Department of Energy 1980 Annual Report to Congress by the Energy Information Administration.

Canadian Gas Imports

Canada's present gas situation may be characterized as one of oversupply relative to that country's internal needs. From 1972-1979, Canada increased its proved natural gas reserves base 46 percent from 61 tcf to 88 tcf. During this same period, internal Canadian gas sales grew less rapidly (34 percent) than the reserves base and a restrictive export policy was designed to reduce the long-term flow of gas to the U.S. This period of "reserves building" resulted in a recognized surplus of available gas by the late 1970s.

In December 1979, Canada's National Energy Board, which approves all gas exports, reversed then existing policies designed to reduce gas exports and allowed the first significant increases in Canada's export levels since the early 1970s. Much of the newly-approved export volumes will move through the "pre-build" western and eastern legs of the Alaskan natural gas pipeline system, commencing in late 1981 and late 1982, respectively. The volumes of Canadian gas available to the L48 are projected to be 1.6 tcf by 1985 and then to decline slightly to 1.4 tcf by 1990 as development of markets in eastern Canada occurs, siphoning off the exportable gas surplus.

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[1] National Research Council, U.S. Energy Supply Prospects to 2010, 1979.

Despite the existing availability of surplus gas in Canada, 1980 gas exports to the U.S. plummeted 17 percent from 1979 levels, or from 1,001 bcf to 833 bcf. This decline was due to a number of interrelated factors, including economic recession effects in regions traditionally dependent on Canadian gas, an abundance of residual fuel oil and increased availability of L48 pipeline gas in those regions and, most importantly, an increase in the Canadian gas export price from $3.45/mcf at the beginning of 1980 to $4.47/mcf by April 1, 1980. Canada has announced a gas export pricing policy based on "value substitution" or price linkage with imported Canadian crude oil. However, the decline in Canadian gas export demand has ameliorated the implementation of this policy (i.e., a planned October 1980 export gas price increase was delayed until April 1, 1981, and was then posted at $4.94/mcf--below the possible crude oil-linked formula price). Over the long-term, and as traditional U.S. markets for Canadian gas strengthen, we expect Canadian gas export prices to escalate in step with world oil prices.

Mexican Gas Imports

Mexico's successes in gas and oil exploration in the past decade have resulted in that country's recent re-emergence as a major energy exporter. Mexican export gas began flowing in January 1980, at the rate of 300 million cubic feet per day (0.1 tcf/year) under a contract with a six-company U.S. consortium called Border Gas, Inc. Moreover, Jensen Associates projects U.S. imports of Mexican gas to increase to 0.4 tcf in 1985 and to reach 0.7 tcf by 1990.

Mexico's proved gas reserves are now estimated at over 80 tcf, with an additional 72 tcf of probable reserves. Most of Mexico's gas production is associated or co-produced with crude oil; hence, as Mexico has increased its crude production levels, gas production has similarly increased. For example, between 1978 and 1979, gas production increased 14 percent as a result of Mexico's attainment of crude oil production goals. And while Mexico is engaged in major efforts to reduce gas flaring through reinjection of gas into reservoirs and through utilization of gas domestically, we expect that the overall availability of gas coupled with the favorable economics of pipeline gas flows will mean increased gas exports to the U.S. by the mid 1980s. Existing pipeline facilities linking Mexico's gas producing areas to U.S. markets will need to be expanded to accommodate higher export levels; however, a large-diameter branch pipeline to the U.S. was originally envisioned as part of Mexico's developing gas grid network and we would anticipate construction of such a pipeline by the mid 1980s.

Although Mexico has announced an energy policy limiting gas exports to present levels, we expect that this posture will be ameliorated over the longer-term by general gas availability, gas export revenue considerations and physical limitations on utilizing the gas internally.

Mexico's current gas export price is tied directly to the prices of five key world export crudes with a contract provision permitting price parity with the Canadian export gas prices, should the latter be higher. In our forecast, we have assumed price parity with Canadian gas.

Liquefied Natural Gas (LNG) Imports

The optimistic outlook of the mid 1970s for large-scale movements of LNG to the U.S. by the early 1980s has gradually succumbed to the realities of major obstacles to such projects. Public concerns about the safety of LNG shipments, local objections to proposed terminal sites, government fears of gas over-dependence on foreign sources, doubts about the pipelines' needs for LNG supplemental gas, and U.S. government policy preferences for other supplemental gas sources have all played a part in reducing many LNG import proposals to little more than hollow possibilities. Of some 14 often-cited "probable and possible" U.S. LNG projects of the mid 1970s only two reached operational status (an expanded Distrigas project using facilities already in operation by 1972 and El Paso I), with a third project (Trunkline LNG) scheduled for start-up in August of 1981. All are based on Algerian-source gas.

The pricing of LNG has always been a difficult issue to resolve because of the massive investments required of both exporter and importer and the disparate government perspectives of LNG producing and consuming countries on the value of the gas to the user. Recent producing country pressure for f.o.b. gas pricing parity with crude oil has added to the difficulty of negotiating an LNG price acceptable to all parties.

LNG deliveries under the El Paso I project have been disrupted since April 1980 because of the gas pricing issue, although volumes under the much smaller Distrigas project have continued to flow. Despite the announced financial write-off by El Paso LNG of some $375 million of its LNG investment (after termination of U.S.-Algerian government pricing talks in February 1981), we believe there is a reasonable likelihood that deliveries--possibly at reduced levels--under this project will resume. The U.S. pipeline purchasers of El Paso I LNG are making efforts to negotiate directly with Algeria on the gas pricing issue and, in addition, the LNG tankers dedicated to this project have not yet been committed elsewhere. Thus, our 1985 supply forecast includes a contribution of 0.5 tcf from the El Paso, Distrigas and Trunkline projects.

Currently, four other LNG projects--Pac Indonesia, Pac Alaska, Nigeria Bonny, and Trinidad/Tobago--are in varying stages of planning or regulatory approval. In our estimates, we have assumed that additional LNG volumes of 0.2 tcf will come on stream in the latter half of the 1980s. We assume that any additional volumes, from these or other projects, will probably not be operational until after 1990.

Unconventional Production

Unconventional sources such as Devonian shales, coal seams, and tight formations are expected to make a small but measurable contribution to total gas supplies over the forecast period. The incentive of deregulation (as of November 1, 1979) for Devonian shale gas and coal-seam gas, along with allowable higher prices for tight gas, should stimulate production from these sources.

Devonian shales extend geographically over one-fourth of the North American continent, with significant deposits in the eastern United States. Miniscule production from this source occurs presently and improvements in exploration technology, allowing better definition of the shale areas and economically producible gas zones within Devonian shales, are expected to increase gas from this source in the latter half of the 1980s.

At least one proposal to tap coal-seam methane on a commercial basis has already been submitted to the Federal Energy Regulatory Commission and gas from this source is expected to make a small contribution to total unconventional production by 1985 and thereafter.

Interest in tight formation gas has been stimulated by the establishment of a special, high-cost incentive price in the NGPA. Some 150 different areas in the U.S. are under consideration for designation as tight gas producing areas. Hydraulic fracturing techniques are currently available to tap tight gas, but according to the National Petroleum Council[1], the technological improvements required to provide their widespread routine application will possibly take 9 to 17 years of intensive research and development effort. Thus, tight gas production from massive, relatively unproductive formations of the West is not expected to become substantial until after the 1980s. Forecasts of natural gas from currently producing tight sands areas are included in the conventional production figures of Table III-1.

Gas supplies from unconventional production are expected to reach a total of 0.1 tcf per year by 1985, and 0.3 tcf by 1990. Most of this will be tight formation gas from newly developing plays.

Another unconventional gas source is geopressured brine, but apparent production costs relative to other unconventional sources suggest that measurable production from this source is unlikely before the late 1990s.

Synthetic Natural Gas (SNG)

1. Liquid feedstocks

During the past two years, the greater availability of less expensive domestically-produced and pipeline imported natural gas has greatly reduced

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1 "Tight Gas Reservoirs-Part I," Unconventional Gas Sources, NPC, December 1980.

the demand for SNG reformed from naphthas and natural gas liquid products. In 1980, SNG supply dropped to 123 bcf. The 13 SNG plants in the U.S. are capable of producing over 300 bcf per year, indicating substantial idle capacity. We expect these plants to operate primarily as peak-shaving facilities until such time that all other less expensive baseload supplies are inadequate to meet demand. Consequently, our forecasts for the years 1985 and 1990 range from a peaking use level of about 0.1 tcf per year to an all-out rate approaching 0.4 tcf per year if demand exceeds supply of all other gas supplements, including Alaskan gas and LNG imports.

2. Coal gasification

The United States is poised on the threshold of developing high-Btu coalgas as a commercial gas supplement. Although the optimism of the mid 1970s, which envisioned production from five, large, pipeline-quality coal gasification projects by 1980 and an additional eleven plants by 1985, is considerably more guarded now, start-up in this decade of the nation's first commercial coalgas plant seems likely.

Several high-Btu synthetic-natural-gas-from-coal projects are under consideration. The Great Plains Gasification Associates proposal for an initial plant output in 1984 of 125 MMcfd of coalgas is most advanced and has received conditional Federal approval of plant financing loan guarantees. At least four other coalgas projects have sought loan guarantees through the Federal Synthetic Fuels Corporation, but the overall level of government financial support for coal gasification is uncertain at this time. Without such assistance, the substantial impediments of plant financing seem certain to further delay most coal gasification projects.

Our forecast for supplemental high-Btu coalgas includes a negligible contribution in 1985 and 0.2 tcf in 1990. This latter amount is equivalent to the output from two plants, each producing 250 MMcfd. In actuality, we expect several smaller-sized plants to be in place by the end of the 1980s.

Alaskan Pipeline Gas

Initial deliveries of natural gas from Prudhoe Bay through the Alaskan Natural Gas Transportation System are scheduled to occur in 1987. The forecast of 0.7 tcf in 1990 represents gas deliveries to the L48 States. It excludes deliveries to Alaskan users and transmission fuel.

IV. THE DEMAND FOR NATURAL GAS

Energy prices have been a major political and economic issue during much of the last decade. Policymakers have debated whether energy prices should be allowed to increase, who should reap the benefits of any price increases, and how the burden of any increases should be distributed. Proponents of a free market system have compromised their preferences to accommodate the social welfare concerns of the market regulators. As a consequence, our current energy pricing policies may be characterized as a complex system of partially regulated prices attempting to selectively emulate a market system, while still keeping consumer prices below market clearing levels. In the course of the decade, however, energy prices have risen substantially due to the changes in international petroleum markets.

These higher prices, in conjunction with both projected and realized fuel shortages, have altered the market for all energy. This is particularly true for natural gas. Conservation has reduced the requirements for all energy, while the gas shortages of the mid 1970s--which required the expansion of alternate fuel capabilities--have increased the fuel choice options of many commercial and industrial firms. In the next decade, continued conservation and intensified interfuel competition following deregulation of natural gas will have substantial influences on the demands for natural gas.

Our demand forecast is summarized in Table IV-1. Residential and commercial demands are expected to be relatively stable over the next decade as demand from new customers is offset by conservation from existing customers. Industrial demand is expected to increase substantially as the gap between gas and oil prices widens between now and 1985, when price controls end for a large part of gas supply. This growth is strongest in the premium process and smaller boiler fuel markets in the major natural gas producing areas where the imposition of Federal price controls has re-established natural gas as the preferred industrial fuel. Subsequent to deregulation, however, the industrial market for gas is expected to contract substantially as alternate fuels become more attractive. The electric power generation demand for gas is not expected to experience the same level of growth as the industrial sector prior to 1985, but will shrink similarly following the rapid escalation in prices expected in 1985.

Residential/Commercial Demand

The rapid growth in new gas customers that prevailed in the 1960s declined appreciably in the 1970s with the advent of interstate pipeline curtailments. The restrictions on new customer additions, particularly widespread in the East, effectively removed many gas utilities as a competitive force in the new construction market. At the same time, existing residential gas customers were adjusting their consumption downward in response to the real increases in their cost of natural gas.

TABLE IV-1

LOWER 48 STATES DEMAND FOR NATURAL GAS

1979-1990

(Quadrillion Btus)[a]

	Actual	Forecast		
	1979	1984	1987	1990
Residential	5.1	5.0	5.0	4.9
Commercial	2.8	2.7	2.7	2.7
Industrial	7.0	9.4	7.2	6.9
Power Generation	3.3	3.5	2.5	2.2
Other	2.9	2.3	2.1	2.0
Total Demand	21.1	22.9	19.5	18.7

[a] The gas data in this chapter are all in quadrillion Btus. The supply/demand balances in Chapters I, III and V are all in trillion cubic feet.

Source: Jensen Associates, Inc.
Gas Requirements Agency

The effect of conservation on residential gas demand has been less pronounced than in the commercial and industrial sectors, however, because the incentives to conserve have not been as strong. Subsequent to the OPEC oil price increases in 1973, the price of all energy began to rise. Higher wellhead prices allowed by the Federal Power Commission, rapid increases in unregulated intrastate wellhead prices, the addition of relatively expensive supplemental gases and lower interstate sales volumes all contributed to the increased city gate prices for gas. These price increases were not allocated evenly among all customer classes, as shown in Table IV-2. During this period, residential gas prices actually increased less than the average city gate price, while industrial prices increased substantially more than the average city gate cost. In effect, the increases in petroleum prices elevated the threshold price at which industrial users would begin to shift to alternate fuels--principally oil--thereby allowing them to bear a greater burden of gas costs. With continued increases in natural gas costs against a background of deteriorating real petroleum prices, the ability of regulatory agencies to augment this effective subsidization of residential consumers diminished. By 1978, further wellhead gas cost increases were necessarily reflected in residential prices, although the implicit city gate cost to residential customers remained lower than that for the industrial sector. The 48 percent real increase in residential gas prices did prompt residential consumers to reduce their average normalized consumption by 12.5 percent, but both commercial and industrial conservation levels were substantially higher.

Three subsequent events have re-established the potential for further subsidization of the residential sector: the passage of the incremental pricing provision in the Natural Gas Policy Act; the rapid escalation of world oil prices following the Iranian Revolution; and the decontrol of U.S. crude prices. The collective effect of these events has been to again raise the fuel switching threshold for industrial gas customers. However, while residential natural gas prices are not expected to increase to the same degree as will other sectors, the real cost of space heating will continue to rise, prompting further residential conservation. By 1985, we project residential conservation to reach 22 percent (on a per customer basis relative to 1972) and rise to 27 percent by 1990.

Implicit in this analysis is the expectation that a substantial number of new customers will be added to the gas distribution network. Although some of these new customers will be conversions from other fuels in existing structures, new construction represents the majority of these new attachments. Because these new units are much more efficient than the average existing house--not only in the space heating requirements of the building but also in the efficiency of the heating system--their addition reduces the average usage-per-customer.

With the removal of the state moratoriums on new customer additions, the gas market share in new construction is expected to rebound from the low levels of the 1970s. In the areas of the country where electricity is the principal competitor, however, gas is not expected to always return to

TABLE IV-2

U.S. AVERAGE NATURAL GAS PRICES
1972 - 1979
(1980 dollars per million Btu)

	1972	1979	1972-1979 Increase	1972-1979 % Increase
U.S. Average Wellhead Price ($ per mcf)	$0.34	$1.25	$0.91	272%
U.S. Average City Gate Price	0.78	1.98	1.20	154%
U.S. Average Residential Price	2.15	3.19	1.04	48%
U.S. Average Industrial Price	0.81	2.45	1.64	202%

Source: Jensen Associates, Inc.
U.S. Department of Energy
American Gas Association

its pre-shortage market share. Between 1972 and 1979, when residential gas prices rose 48 percent in real terms, residential electricity prices only increased 14 percent in real terms. The price of electricity relative to natural gas had actually fallen by 23 percent as illustrated in Table IV-3. This trend is expected to continue throughout the forecast period. Although gas prices remain well below electricity prices, the effective heating cost of gas approaches that of electricity by the end of the decade. As a consequence, although the number of new, gas space heating customers will increase annually, the gas market share in new construction is expected to decline.

The Northeast region, where oil is the principal competing space heating fuel, is an exception. The natural gas price advantage over distillate oil that developed with the Iranian revolution is expected to be maintained throughout the decade. Following deregulation in 1985, this competitive advantage is diminished so the high level of conversions from oil to gas in existing homes tapers off, but gas does continue to capture a higher share in the new construction market.

Despite the consumer preferences for natural gas, however, natural gas distributors may become somewhat cautious about new residential connections. As gas costs continue to rise, new homes will become increasingly efficient. With very low consumption levels, the rate of return on the investment in new mains required to attach new customers may decline sufficiently to make the investment unattractive. This could be accentuated with an inverted marginal cost rate structure where negative rates of return on the residential rate base are possible. Under these circumstances, while natural gas demands would be lower than shown in Table IV-4, the effect would likely be small due to the low consumption levels in these new units.

The commercial sector's consumption patterns are more varied than those in the residential sector, but the basic changes are quite similar. Commercial conservation has been slightly higher because the incentives were greater. Absent the subsidies reaped by the residential sector, and frequently facing higher rates of return on conservation investments, the commercial sector responded more quickly to rising gas prices. However, the ultimate potential conservation in this sector is lower than the potential in the residential sector--due largely to the smaller surface areas per unit of volume in commercial buildings. For this reason, commercial consumption-per-customer is forecast to decline at a lower rate than projected for the residential sector.

The net effect of the residential and commercial customer growth and conservation are shown in Table IV-4. Overall, residential demand is projected to increase (due in large part to a substantial number of oil to gas conversions) through 1985, and then decline as conservation more than offsets the demand of new customers. For the commercial sector, demand is expected to be relatively stable throughout the forecast period.

TABLE IV-3

U.S. AVERAGE RESIDENTIAL ENERGY COSTS

(1980 dollars per million Btu)

	1972	1979	Percent Change
Gas	$ 2.15	$ 3.19	48%
Electricity	$12.15	$13.88	14%
Relative Prices (Ratio of Electricity to Gas Price)	5.65	4.35	(23%)

Source: Jensen Associates, Inc.
American Gas Association
Edison Electric Institute
U.S. Bureau of Labor Statistics

TABLE IV-4

RESIDENTIAL AND COMMERCIAL GAS DEMAND
1979 - 1990
(Trillion Btu)

	1979		Forecast		
	Actual	Normalized	1984	1987	1990
Residential	5,131	4,834	4,987	4,963	4,904
Commercial	2,760	2,606	2,679	2,686	2,682
Total	7,891	7,440	7,666	7,166	7,586

Source: Jensen Associates, Inc.
Gas Requirements Agency

Industrial Demands for Natural Gas

The increase in delivered price of industrial natural gas during the latter half of the 1970s (see Table IV-2) had two major effects on the markets for gas--it provided an incentive for industrial firms to conserve by improving their energy efficiency, and it reduced the industrial demand for gas in selected applications when other fuels became the lowest cost source of heat. The net effect of these two changes was to substantially shrink the overall demand for gas, so that the chronically short market of 1976 became a relatively balanced market by 1978.

The measurement of conservation is a complex exercise, in part because it has more than one definition. From an engineering viewpoint, conservation is the reduction in fuel use required to produce a particular product --either because of improved operating procedures or technological change. This is basically what the U.S. Department of Energy compiles in its voluntary industrial conservation program for which conservation (relative to 1972) is estimated at 14 percent as of 1978. However, viewed from the broader perspective of total industrial output, conservation (measured as the reduction in fuel use per unit of output) had reached 24 percent by 1978. This significantly larger estimate suggests a shift in the types of products produced, with energy intensive products declining and other products increasing.

In addition to this shrinkage of the industrial market due to conservation, the actual and anticipated gas shortages, which began with the interstate pipeline curtailments in 1971, created a more price-sensitive fuel market as alternate fuel capability was added and expanded. The large segment of the industrial fuel market that is now dual-fueled only needs to examine operating cost differentials and product quality premiums when choosing fuels. An examination of the fuel switching and market share adjustments that occurred between 1972 and 1978 shows that oil captured three-quarters of the shift (see Table IV-5). Coal usage declined despite the Federal efforts to shift industrial boilers to coal. Although the purchase price of coal is generally less than oil, the higher investment and operating costs for coal (as well as the environmental difficulties associated with coal) appear to more than offset this initial advantage. Most increases in coal use by industry are expected to be associated with new facilities because conversion of gas-fired equipment to coal is generally impractical.

The Powerplant and Industrial Fuel Use Act (FUA), passed as part of the National Energy Act in 1978, represents an effort to shift industrial and electric utility boilers from gas and oil to coal by legislative fiat rather than through the creation of economic incentives. The industrial portion of the Act is summarized below.

New Major Fuel Burning Installations (MFBI)

New MFBI boilers would be prohibited from burning oil or natural gas. Non-boiler usage at new MFBIs would be subject

TABLE IV-5

TOTAL U.S. INDUSTRIAL FUEL SWITCHING
1978
(Billion cubic feet gas equivalents)
Base Year 1972

Fuel	Volumes	Percent
Residual Oil	+498	+47%
Distillate Oil	+305	+29%
Refinery Gas	+209	+20%
Other	+ 59	+ 6%
Coal	- 21	- 2%
Subtotal	+1050	+100%
Natural Gas	-1050	-100%
Net Fuel Switching Between Fuels	0	0

Source: Jensen Associates, Inc.
Gas Requirements Agency
U.S. Department of Energy

to a case-by-case prohibition. Exemptions would be allowed for process use, cogeneration facilities, and for compliance with environmental laws.

Existing MFBIs

Existing MFBIs using more than 300 mcf per day must switch from oil and natural gas if they are economically and technically capable.

In our analysis we have assumed that the FUA will be strictly applied to new boilers and no new MFBI boilers will be permitted to burn natural gas. The actual effect of the legislation on the existing industrial market hinges upon the executive interpretations of the rules for exemption, which include economic, technical and environmental criteria. In the near term, the impact of the legislation is expected to be limited by the small number of gas-coal fired boilers.

The incremental pricing provisions of the NGPA attempted to provide the economic incentives for industrial boiler conversions that were lacking in the coal conversion program. However, in order to limit load shifting to petroleum products, the FERC regulations set a ceiling on industrial gas prices equivalent to the prevailing high-sulfur residual fuel oil price. The effect of the ceiling is to limit the economic penalty incurred by industrial gas users who choose not to convert their existing facilities to coal.

The competitive position of natural gas has changed several times in the last decade. Industrial gas was delivered to users at near parity with residual fuel oil in the stable pre 1970s period. It was thus priced well below distillate. The first pipeline curtailments began in 1971. In late 1973 and early 1974, OPEC initiated the dramatic increases in international oil prices, thereby creating a significant competitive price advantage for natural gas. Between 1974 and 1978, however, oil prices declined in real terms while industrial gas prices continued a steady rise. In an effort to protect residential consumers from higher gas costs, utilities and regulatory commissions passed on a disproportionate share of the higher gas costs to industrial customers (as was shown in Table IV-2). By 1978, the price of industrial gas and residual fuel oil again approached parity.

The NGPA has institutionalized this practice of rate tilts for industrial boiler fuel customers. In fact, the industrial boiler fuel customer shifts from paying the lowest price for natural gas to paying prices occasionally above even the residential consumer. The disproportionate share of gas costs paid by industrial firms subject to incremental pricing effectively subsidizes other gas users. This subsidy is in addition to the subsidy inherent in the maintenance of wellhead price controls until 1985. As a consequence, natural gas regains the price advantage that prevailed from 1974 to 1978, particularly for the non-boiler fuel users of gas exempt from incremental pricing.

This competitive price advantage creates a substantial increase in demand for natural gas through 1984. In 1979 and 1980, the principal growth in gas demand was in the power generation sector for two reasons. Being exempt from incremental pricing, electric utilities found it quite attractive to substitute natural gas for oil. Secondly, the sluggish market for industrial gas (due to the slowly emerging recession) freed up volumes that could easily be absorbed into the electric utility market. For the balance of the period, the principal growth sector is expected to be industrial process gas users, particularly in the West South Central region (Texas, Louisiana, Oklahoma and Arkansas). With the NGPA-imposed price controls on intrastate gas (which previously had been unregulated), natural gas again becomes a very attractive fuel in the producing states.

Whether or not this demand actually materializes will depend on a number of non-price influences. Industrial users may be reluctant to attach new plants to natural gas systems without strong assurances of supply that may not be forthcoming. Secondly, following the substantial wellhead price increases expected to occur with deregulation in 1985, some industrial customers may chose to forego the price benefits in the short term. In any event, the rapid increase in deregulated gas prices in 1985 will have several effects. The subsidy effects of wellhead price controls will be largely eliminated, causing the industrial gas markets in the producing states to deteriorate. Secondly, the industrial gas customers that are exempt from incremental pricing will find their "subsidy" substantially diminished, thereby reducing the interstate industrial gas demand.

The Federal efforts to expand industrial utilization of coal have been largely resisted, not only because of the enormous capital costs of the conversion from gas or oil, but also because of local and Federal air quality standards. It is frequently suggested that an easing of the Clean Air Act would result in expanded use of coal at the expense of other fuels. A relaxation of environmental regulations would not affect our estimated gas demands from new boilers since we have already assumed a strict interpretation of the Fuel Use Act restrictions precluding gas consumption in new MFBI's. In existing facilities, a moderation of Federal environmental policy would be expected to increase industrial coal consumption. However, such a policy shift would not have a substantial impact on our industrial gas forecast.

There are two major causes for this apparent insensitivity to policy changes. The barriers to increased coal usage go beyond environmental regulations. Since converting existing gas and oil fired facilities to burn coal is largely technically infeasible, expanded coal use typically requires replacement of current equipment--an expensive proposition made more difficult by high capital costs, the competition for internal corporate funds and such mundane problems as inadequate land in many old industrial sites. In addition, because of the higher gas prices subsequent to deregulation, a large share of the industrial boiler market is already forecast to shift to alternate fuels. Since the boiler market is where additional coal use is expected to have its greatest impact--and our projections already reflect significantly diminished use of gas under boilers--our industrial gas demand forecasts are not particularly sensitive to changes in environmental regulations. Coal consumption does expand, but at the expense of non-gaseous fuels.

Our industrial forecast is summarized in Table IV-6. Total stationary industrial energy demand is expected to increase three percent per year to 1990, with most of the increase occurring by 1985. Industrial conservation will continue to temper industrial demand, particularly after 1985 with its large increases in industrial energy costs. Industrial demand for natural gas will peak in 1985 and then decline as the most price-sensitive markets switch to other fuels. As a consequence, industrial gas markets in 1990 will not be substantially different than those that existed in 1979.

<u>Gas Demand in the Electric Utility Sector</u>

The demand for gas for the generation of electricity in the 1980s will be characterized by the following general conditions:

- overall, use of gas as a fuel in electricity generation will generally decline vis-a-vis other fuels;

- the greatest potential demand for gas in electricity generation will occur in the near term, with total potential demand generally declining annually through 1990;

- the demand for gas by electric utilities will, however, be constrained by the volumes of gas available for large boiler fuel uses--hence, unsatisfied gas demand will exist among electric utilities prior to deregulation;

- unsatisfied gas demand in the electric utility sector will be met primarily by oil, since generating facilities based on other fuels such as coal, uranium, and hydropower will already be operating at or near their functional upper limits.

In the 1970s, many electric utilities accustomed to using gas for power generation were forced by the onset of gas curtailments to turn to alternative generating fuels. In 1970, gas demand by electric utilities was 3.9 tcf and by 1977 had dropped to 3.2 tcf. With the return of gas availability to the large boiler fuel market, gas consumption for electricity generation had increased and in 1979, electric utilities consumed 3.3 tcf of gas. For 1980, we expect that gas demand from electric utilities (unconstrained by supply) will have risen even more--to approximately 3.7 tcf--and then begin declining over the rest of the decade.

TABLE IV-6

INDUSTRIAL NATURAL GAS DEMAND
1979 - 1990
(Trillion Btu)

	Actual 1979	Forecast 1984	1987[a]	1990
Demand	6,973	9,410	7,166	6,949
Expected Deliveries	6,973	7,068	7,166	6,949[b]
Deliveries as a Percent of Demand	100%	75%	100%	100%

[a] The 1987 and 1990 demand forecast is based on a cleared market for natural gas.

[b] Includes Alaskan volumes.

Source: Jensen Associates, Inc.
Gas Requirements Agency

The reason for the longer-term decline in the role of gas as an electricity generating fuel is that gas (and oil) is increasingly being relegated to a peakload generating status from its previous role as a baseload generating fuel. In effect, generating facilities designed to burn gas and/or oil are being used less than facilities based on other fuels--namely coal and uranium. Thus, the share that gas and oil together hold of the generating fuels market is declining. However, within this joint gas/oil share of the generating fuels market, gas has recently been gaining share vis-a-vis oil. In 1977, gas and oil accounted for 31 percent of the 2,115 billion kilowatt hours generated in the Lower 48 States. In 1979, this share dropped to 28 percent. Looking only at gas versus oil generation, gas accounted in 1977 for 46 percent of the 655 billion kilowatt hours generated by oil and gas together. By 1979, gas and oil were together utilized to generate only 624 billion kilowatt hours of electricity, but gas accounted for 53 percent and oil the remainder--a reversal of their position in 1977.

Over the 1980-1990 forecast period, we expect that oil will continue to be regarded as a fuel of last resort in the power generaton sector. Similarly, gas will tend to share this characteristic, but the effects of rolled-in pricing on the gas side along with the existence of some low-priced, fixed gas contracts between some electric utilities and their gas suppliers, will make gas considerably more attractive than oil in those locales where it is available for power generation markets.

V. SUPPLY/DEMAND BALANCF

The increase in natural gas demand between now and 1985, prompted by the competitive price advantage of natural gas prior to deregulation, is not matched by an improvement in natural gas availability. As a consequence, a not inconsiderable gas shortfall is expected to develop, as shown in Table V-1. Since this shortfall is not due to a sudden decline in supply--as occurred in the interstate markets in the early 1970s with the advent of curtailments--but rather is due to a surge in demand, the gas industry can effectively manage the shortfall by carefully planning new load additions.

This excess demand collapses following the deregulation of wellhead prices when prices are free to rise to market clearing levels. In the post deregulation period, gas may be priced above the value of other fuels in some regions of the U.S., causing large users to switch away from gas and thereby reducing overall demand for gas. During the 1980-1984 period, there will be buyers who are willing to pay the regulated prices for gas, but cannot obtain it because supply is unable to keep up with demand.

The magnitude of the post January 1, 1985 adjustment in gas prices is dependent on the price of alternate fuels that will determine a market clearing price for gas. Based on our lower-bound oil scenario, the roll-in capacity (resulting from continued price controls on selected gas categories) in 1986 is estimated at approximately $13 billion. Supplemental gas premiums above the market clearing price absorb $2 billion and the balance represents the potential for flyup.

One of the key elements in establishing the level of flyup will be the price of residual oil because natural gas competes with residual oil in important marginal markets. High-priority markets typically develop rather slowly. Large increments of new supply can generally be quickly absorbed only in boiler fuel markets, and Alaskan gas is no exception. Thus, the initial deliveries of Alaskan gas are principally in low-priority uses--either directly or by displacement--where their major impact is to displace foreign oil. Gradually, the availability of the Alaskan natural gas allows high-valued process markets to expand their utilization of gas.

Since we expect petroleum product price spreads to be wider in the future, it would appear that refiners would have incentives to expand their yields of light products. Typically, such refinery upgrading would lead to reduced supplies of residual oil with attendant strengthening of residual oil prices--a scenario that would improve the market for natural gas. However, our analyses suggests that a substantial level of refinery investment will be necessary to keep residual oil yields no higher than they are presently due to the deteriorating crude slate available to U.S. refiners. Because of a petroleum product slate biased toward light products such as

TABLE V-1

SUPPLY AND DEMAND FOR U.S. NATURAL GAS

1980 - 1990

(Trillion cubic feet)

Potential Gas Demand	Estimated 1980	Forecast 1984	1987	1990
Residential	4.8	4.9	4.9	4.8
Commercial	2.6	2.6	2.6	2.6
Industrial	6.8	9.2	7.0	6.8
Power Generation	3.7	3.4	2.4	2.2
Other	2.6	2.3	2.1	2.0
Total Potential Demand	20.5	22.4	19.0	18.4
Expected Gas Supply				
Total Supply (Excluding Alaska)	20.5	19.2	18.3	17.7
Shortfall				
Without Alaska	--	3.2	0.7	0.7
With Alaska	--	3.2	0	0

Source: Jensen Associates, Inc.
Gas Requirements Agency

gasoline, U.S. refiners generally prefer the light African crudes from Nigeria, Algeria or Libya--crudes that are not substantially different from domestic crudes.

These light crudes typically have very low residual fuel oil yields. However, world reserves of crude oil are increasingly biased toward heavy crudes that yield significantly higher outputs of residual oil. If residual fuel oil supplies remain high relative to the market, it tempers the degree of flyup. The essentially by-product residual oil produced will be priced as low as necessary to dispose of it, thereby softening natural gas prices. The 1979-1980 collapse of the residual fuel oil market in the Midwest is a good example. Excess supply of residual oil caused the price to drop substantially at a time when crude oil prices were rising. As a consequence, natural gas prices in some industrial markets relaxed in order to maintain market share in the face of a shrinking overall demand for energy due to the economic downturn that affected the Midwest so strongly. Such events are likely to occur again subsequent to 1985. Although our forecast suggests an essentially balanced market, sporadic market disorder (created by abrupt changes in economic activity, large increases in supply, etc.) may occasionally cause spot surpluses and shortages.

Comparison of our supply and demand forecasts indicates a gas surplus during all of 1980 and 1981, reaching a balance during 1982 and shortfalls in 1983 and 1984. Then, following market adjustments to large gas price increases which occur in 1985, we find a continuing balance of supply and demand through 1990. Figure V-1 summarizes these changes in gas market balances for the years 1980, 1984, 1987 and 1990. This graph shows that in 1980, a total gas supply surplus of about one-half tcf existed and that this situation is expected to change to a shortfall of over 3 tcf by 1984. Following the 1985 gas price increases from decontrol, supply and demand will be essentially in balance.

The Impact of Early Deregulation

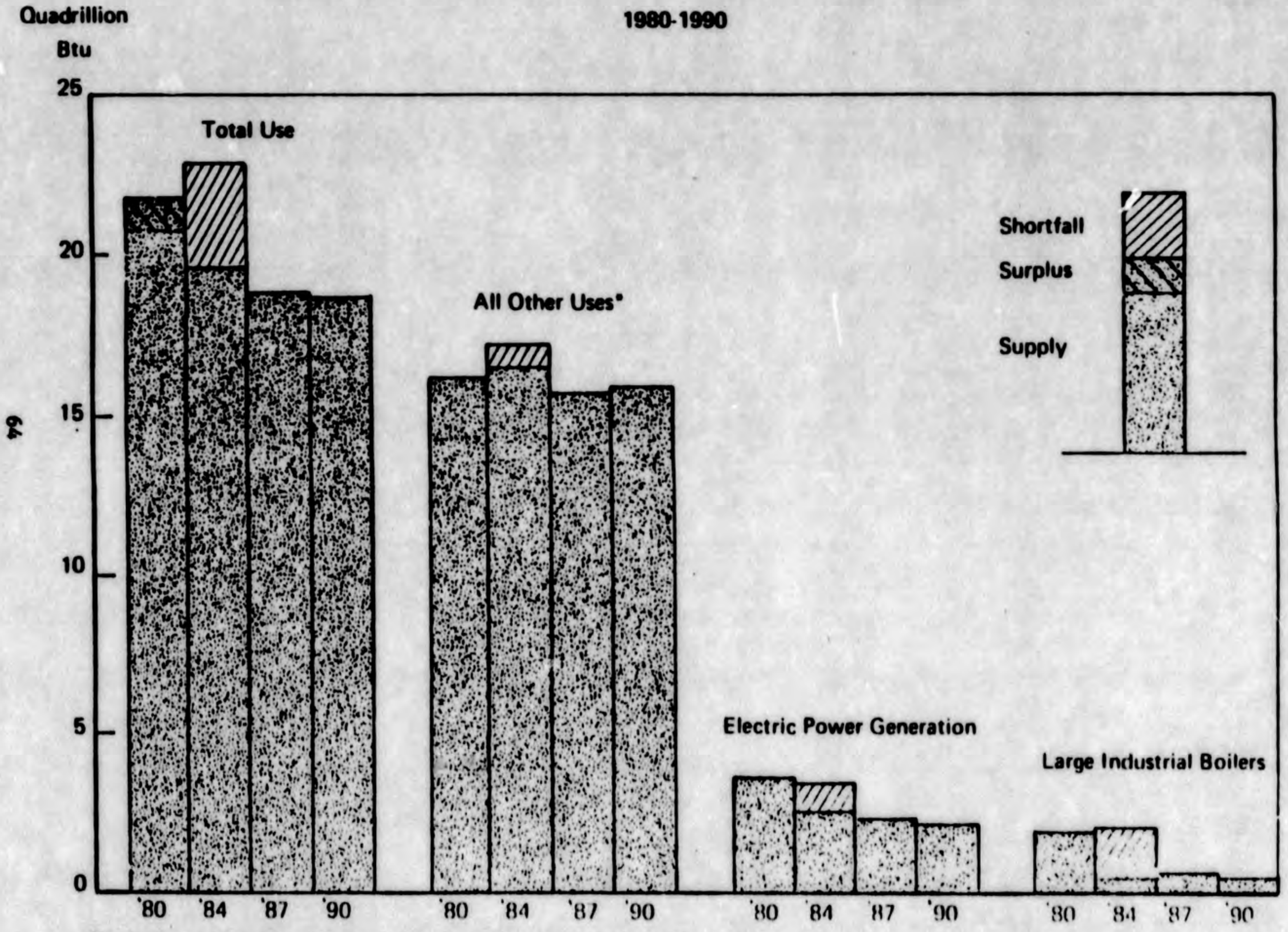
The election of Ronald Reagan, together with a Republican Senate in November 1980, has signalled a conservative shift in American politics. Reagan's economic advisers strongly support private sector investment and economic activity under the stimulus of market forces. In oil and gas, the emphasis on supply-side economics quickly translates into deregulation. Deregulation of crude oil was quickly accomplished in January 1981 by Presidential order; an accelerated timetable for new natural gas deregulation or full deregulation would require Congressional action, but may well be proposed by the Administration. The analysis in this report is largely based on an assumption of the continuation of the Natural Gas Policy Act of 1978, which provides for new gas deregulation in 1985. The major question which naturally follows is, "What would be the effect on markets for Alaskan natural gas?"

We have not examined early deregulation in detail and therefore can only speculate about its possible effects on Alaskan gas markets. We do

FIGURE V-1

GAS SUPPLY/DEMAND BALANCES BY USER TYPES

1980-1990



*Includes residential, commercial, industrial (except large boilers) and other.

Source: Jensen Associates, Inc.

not share the view that immediate gas price deregulation would so stimulate the supply side that it would obviate the need for supplementary sources such as Alaska. We are persuaded that the impact of early deregulation would be much greater on market ordering and on demand than it would be on supply.

Higher oil and gas prices and the prospects for scheduled deregulation have already provided a powerful incentive for drilling activity. Both oil and gas well completion footage have increased by more than 40 percent in the past three years, gas footage nearly quadrupling and oil footage nearly doubling over the decade. The limitations imposed by leasing rates, geophysical crews, drilling rigs, and most importantly, evolving ideas for new drilling prospects serve to restrict the rate at which acceleration of the drilling incentive can produce concrete discovery results. Experience suggests that as drilling activity rises too rapidly, the yield--mcf discovered per foot drilled--may fall to offset the activity increase. Thus, although we would expect to see some supply improvement from immediate deregulation, we would not expect it to be large.

On the other hand, our projection of excess demand for gas is largely dependent on maintaining the disparity between price-controlled gas and international oil prices. Clearly, deregulation would permit gas, oil and coal markets to balance themselves more evenly over the 1981-1985 period, providing a more orderly market in the process. This would, presumably, eliminate much of the excess gas demand. The greatest concern about early new or full gas deregulation is its potential effect on roll-in capacity and the ability to subsidize the early entry of Alaskan gas into Lower 48 markets. In our lower-bound oil price forecast case, Alaskan gas is priced above market clearing levels in the early years and requires roll-in to enable it to compete in the marketplace. An acceleration of new gas deregulation would not significantly alter the relationship between clearing prices and the average price of old regulated gas, and thus--in our view--would not substantially change the extent of roll-in. It would clearly have an effect on the way in which flyup occurs.

Full deregulation, however, would permit all gas to rise to contractually-determined--as distinct from regulatory-determined--price levels. To the extent that indefinite pricing provisions exist in old gas contracts--and much of the old gas in 1987 will be produced from reserves discovered since 1973 where such clauses are common--prices could rise to eliminate a substantial portion of roll-in capacity. There is no guarantee that roll-in capacity would disappear entirely since many contracts have pricing provisions which would prevent their tracking deregulated prices directly. But to the extent that the roll-in capacity which would otherwise serve to cross-subsidize the Alaskan gas is substantially diminished by full deregulation, other means of accommodating the Alaskan price might be utilized. These could include such things as variations in rate design, greater use of market risk clauses or netback pricing approaches. Netback pricing, which is common in a deregulated market economy, sets the delivered price equal to the market clearing level and permits the wellhead price to vary as necessary within the terms of the contract. For crude prices higher than the lower-bound case--such as, for example, our least unlikely case--the issue disappears since Alaskan gas quickly becomes competitive in its own right without the need for roll-in.

THE MARKETABILITY OF ALASKAN NATURAL GAS

A Summary for Congressional Hearings
by Jensen Associates, Inc.

In our studies of the marketability of Alaskan natural gas, we at Jensen Associates, Inc. have concluded that commercial markets will exist for gas from this project throughout the project's lifetime. Despite an acceleration of drilling activity, the long-term prospect is for a decline in natural gas production from traditional Lower 48 sources. As a result, supplements--such as Alaskan gas from this project, imports, and unconventional sources--will be required if the gas industry is to avoid a substantial loss in its traditional contribution to U.S. energy supply. Efforts to diversify energy sources in the U.S. away from oil are continuing, but we believe that on the margin imported oil will remain the chief competitor for natural gas well into the 1990s. We believe that world crude oil prices will inevitably rise in real terms over the course of the project, although the timing and extent of individual price increases will almost inevitably be erratic. For the next year or so prices, indeed, are more likley to fall than to rise. There is thus a likelihood that the initial price of Alaskan gas will be above the price at which gas markets will clear against oil, requiring some price accommodation for Alaskan gas to assure that it can compete. Congress provided just such a transitional pricing approach in allowing roll-in treatment for Alaskan gas under the Natural Gas Policy Act of 1978.

But if for some reason roll-in is not available, changes in the "front end loading" pricing pattern for Alaskan gas, such as netback pricing at the wellhead and levelized rate design, provide similar price accommodation. We thus believe that a market does exist, and that some mechanism can be utilized to assure that prices can be competitive in the early years.

The year 1981 has proved to be a year of extraordinary upheaval in U.S. and world energy markets. The natural gas shortage which plagued the U.S. in the early and mid-1970s has given way to a "gas bubble" which has persisted for so long that many now call it simply a "gas glut." World petroleum markets are in even greater turmoil; the oil price increases which were set in motion by the Iranian revolution in late 1978 have had a major impact on world oil demand. Only a few years ago, many wondered whether OPEC would be willing or able to produce an expected requirement of more than 40 million barrels per day by the mid-1980s. Two years ago, at this time, demand for OPEC oil exceeded 31 million barrels per day and was threatening OPEC's allowable production capacity; at the moment, net demand for OPEC production has dropped to 20 million barrels per day. World oil prices, which rose more than two and one half times in the chaotic markets of 1978 to 1980, are now falling--not only in real terms, but in current dollar prices, as well--as OPEC price hawks are forced to discount to retain some semblance of an oil market share. The changes have been sudden. Even the formal report submitted with this testimony, and which is dated only three months ago, foresaw a drop in OPEC demand this year to 23 million barrels per day from the then statistical base of 25 million barrels per day; it is now 3 million barrels per day lower than that. In this kind of market, it is tempting to conclude that there is enough natural gas, enough oil, and that the energy problem is almost a thing of the past.

The gas from Alaska, however, is not expected to flow until the winter of 1986/1987, so that the markets which concern us are not those of October 1981, but those of 1987 and the years following. A simple observation can illustrate the rapidity with which energy markets can change and place marketability issues in a new context. South Louisiana is a major contributor to today's gas bubble because of the prolific production rates possible with its reserves. If one were to make the simplifying assumptions that depletion rates in the area could be maintained at current levels and that no new discoveries would be made, the gas from South Louisiana would be virtually all gone by the time the Alaskan gas comes on line. South Louisiana is the largest gas producing area in the U.S., representing 26 percent of Lower 48 reserves and 35 percent of Lower 48 production. We do not mean to suggest that these assumptions are realistic, but only to show how greatly energy markets will have changed by that time.

Our evaluation places the marketability question in three broad contexts--the outlook for natural gas demand, the outlook for supply, and the role of price. Estimates of future natural gas requirements have been steadily reduced as observers have become aware of the extent to which natural gas demand is responsive to price. But although target requirements are down, we believe the long-term outlook for Lower 48 production is also down despite current optimistic trends in gas well drilling activity. Thus supplements will increasingly be needed to satisfy the projected requirements.

The underlying driving force which will be most influential in creating increased demand for gas in general, and a market for Alaskan supplies in particular, is an increase in real prices for world oil. A major portion of existing U.S. industrial and power generation plant capacity is designed for oil and/or gas firing and is not readily convertible to coal or other fuels. Thus, rising oil prices quickly shift demand to gas. In addition, prices of most supplementary gas supplies--such as Canadian, Mexican or LNG--are being linked to oil. Rising real prices for oil thus make Alaskan gas--without such linkage--increasingly attractive relative to alternate supplies.

The Outlook For Natural Gas Demand

If the NGPA were to go to term in its present form, we foresee two distinct periods of gas demand behavior during the 1980s. Prior to new gas price decontrol in 1985, gas demand will grow in the price-sensitive industrial and power generation sectors as the price gap between gas and fuel oils remains. By 1983 this increasing demand will have absorbed the current gas supply surplus and exceeded available supply, creating an imbalance period lasting until decontrol of new gas prices in 1985. Following decontrol, gas prices will rise rapidly relative to other fuels causing some loss of demand by industrial and electric utility users. Price will then bring supply and demand into balance for the rest of the decade and beyond.

During the entire decade, residential and commercial demands will remain essentially constant. Industrial and power generation demands will increase significantly through 1984. Following gas price decontrol, the latter two price-sensitive demands will drop sharply as they switch to cheaper fuels.

Our demand estimates are shown in Table I. If the deregulation provisions of NGPA are modified by Congress through some form of accelerated deregulation, the impact on the market would be to clear it earlier, eliminating the excess demand we foresee prior to 1985. The volume effects would tend to be concentrated in those same markets which would not be served under conditions of excess demand--industrial boiler requirements and dual-fueled power generation demand.

The Outlook For Gas Supply

Natural gas reserve additions in the Lower 48 States last exceeded production in 1967 and, as a result, proved reserve levels in the U.S. have steadily declined. The industry has been able to effect a partial offset to this sharp decline in proved reserves by steady increases in the rate-of-take from remaining reserves. This has occurred both as a result of increased emphasis on in-fill and other relatively low-risk development drilling activity, as well as from the fact that the major Gulf Coast producing region is geologically capable of quite rapid depletion rates.

We do not believe that the increased drilling rates which we foresee will be sufficient to offset the steady decline in gas reserves added per foot of drilling effort. Therefore, we expect a continued decline in Lower 48 proved reserves. In addition, because of the changes in regional

Table I

LOWER 48 STATE GAS DEMAND FORECAST SUMMARY

(Quadrillion Btu)

Sector	Estimated Consumption 1980	Forecast Demand 1984	1987	1990
Residential & Commercial	7.5	7.7	7.7	7.6
Industrial	7.1	9.4	7.2	6.9
Power Generation	3.6	3.5	2.5	2.2
Other	2.8	2.3	2.1	2.0
Total Demand	21.0	22.9	19.5	18.7

Source: Jensen Associates, Inc.
Gas Requirements Agency

patterns of discoveries and in the nature of drilling activity, we foresee that at some point, production rates as a percent of proved reserves will peak, causing production to fall more rapidly thereafter. Thus, supplementary sources of gas supply will increasingly be needed to compensate for declining Lower 48 production. We do not share the view that early price deregulation would so stimulate the supply side that it would obviate the need for supplementary sources such as Alaska. We believe the effects of early deregulation would be much greater on market ordering and on demand than it would be on supply.

Our forecast of Lower 48 State conventional production declines by 28 percent between 1980 and 1990. This is partially offset by an increase in supplemental supplies such as pipeline imports from Canada and Mexico, LNG imports, synthetics, Alaskan gas and unconventional production. The result is that total supply declines 11 percent during the decade, from 21.0 quads in 1980 to about 18.7 quads in 1990. Details of our supply forecasts are provided in Table II. Our gas supply/demand balance--under the assumption of continuation of NGPA as it stands--are shown in Figure I.

The Role of Price

Perhaps the single most important element in competitive fuel price formation during the 1980s will be the outlook for international oil prices. Rising real prices for OPEC oil supplies have two important effects on oil and gas competition. First, rising oil prices tend to stimulate the demand for gas at the expense of oil--particularly in the price-sensitive dual-fuel market. But since prices of most supplementary

Table II

LOWER 48 STATES GAS SUPPLY FORECAST SUMMARY

(Quadrillion Btu)

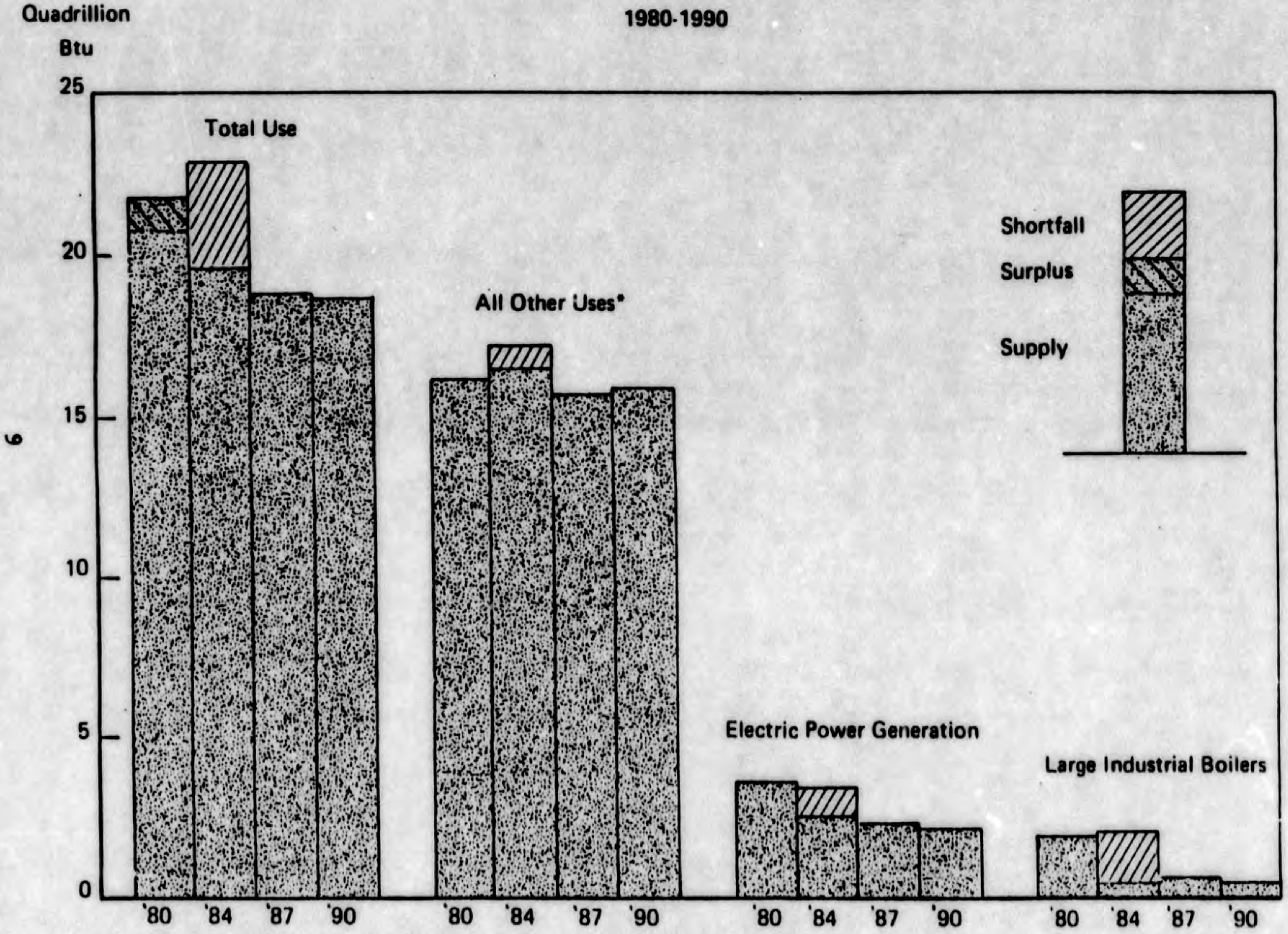
Source	Estimated 1980	Forecast 1984	1987	1990
Conventional Production	19.9	16.8	15.5	14.4
Unconventional Production	--	0.1	0.1	0.3
Imports	1.0	2.6	2.9	2.9
Alaskan North Slope	0	0	0.8	0.8
Synthetics	0.1	0.1	0.2	0.3
Total Supply	21.0	19.6	19.5	18.7

Source: Jensen Associates, Inc.
Department of Energy

Figure I

GAS SUPPLY/DEMAND BALANCES BY USER TYPES

1980-1990



*Includes residential, commercial, industrial (except large boilers) and other.

Source: Jensen Associates, Inc.

supplies, such as LNG or overland imports, will increasingly be tied to international oil price levels, rising oil prices make these sources relatively less attractive by comparison with Alaskan gas. Thus, a rising oil price environment makes Alaskan gas increasingly competitive, not only with oil, but with most other supplementary gas sources as well.

The year 1981 has seen a marked shift in the outlook for world oil supplies and prices. The successful weathering by world oil markets of the Iraq-Iran crisis, together with unexpectedly high reductions in world oil--and OPEC oil--demand has forced most oil economists to moderate their projections. In our formal report we utilize a "lower bound" oil price projection to test the marketability of Alaskan gas. We believed at the time the report was written--and believe now--that the "lower bound" price projection is a conservative statement of oil price behavior over the decade. But with the events in world markets of the summer and fall of 1981, it is probably no longer appropriate to describe it as a "lower bound" case in the early years before Alaskan gas flows, since the turnaround in world oil demand may be extended beyond 1983. Our forecasts of long-term crude prices continue to reflect the expectation that price behavior during crisis will be a major element of future oil price formation.

From 1973 to 1981, prices of international oil to U.S. markets rose at an average rate of nearly 14 percent per year in real terms. This was not a classical steady growth curve, however, since virtually all of the increase was confined to two comparatively short periods--October 1973 to February 1974 during the Arab oil embargo, and again from December 1978 to

February 1980 precipitated by the Iranian revolution. There is thus compelling evidence that the dominant force in real price increases over the decade has been the panic buying which accompanied the crisis markets of 1973/1974 and 1978/1980 rather than any orderly price administration by OPEC. OPEC's principal role has been to resist the erosion of real oil prices during the periods between rises. A forecaster who ignored the crisis element would have been right nearly seventy percent of the time, but might have missed the action of markets during which nearly eighty percent of the price increase occurred. The crisis element in price formation arises when political disruption coincides with a high level of net demand on OPEC. The coincidence was there in 1973 and again in late 1978. Prices weathered one tight market in late 1976 without taking off since the element of political disruption was missing. Conversely, the onset of the Iraq-Iran war occurred while markets were softening and the assassination of Anwar Sadat occurred at the lowest level of net demand for OPEC oil in the last thirteen years.

The magnitude of the present drop in OPEC demand, and the anticipated return of Iraq and Iran to the market, have convinced many observers that tests of OPEC's willingness or ability to produce are a thing of the past. But current production levels are misleading in a world in which OPEC tends to absorb much of the energy downswing, and a combination of worldwide economic downturn and contraseasonal inventory liquidation has pushed OPEC demand to abnormally low levels. For example, current estimates of worldwide inventory liquidation range as high as two million barrels per day during a season when inventories are normally expected to increase by two million barrels per day--a four million barrel per day swing. In our view, net demand on OPEC oil will increase again after the completion of the current inventory liquidation, and a resumption in growth of economic activity in the OECD, perhaps during 1983. With the limited prospects for any significant increase in OPEC's available capacity over the decade, we believe that capacity--and price--will be tested again even without a new major disruption in the Middle East.

In our formal report, we have utilized two forecasts of oil prices. One of these--our least unlikely case--was based on the expectation that international oil price formation would operate very much during the 1980s as it has during the 1970s. The dominant feature of recent international oil price development has been a sporadic political or military crisis in the Middle East; this has generated panic buying in the marketplace and a rapid escalation in oil prices. These prices subsequently decline in real terms as the disruption passes and world economic activity reacts to the sharp dislocations in pricing. For our least unlikely case, we arbitrarily assumed that a disruption would occur in 1984 and the pricing pattern both during and after the disruption would be similar to 1973/1974 and 1979/1980.

For purposes of our market analysis, however, we have assumed that such a forecast, with its disruptive price pattern, would not present a credible test of the marketability of Alaskan gas. Therefore, we have utilized instead a "lower-bound" price case which assumes declining real prices through the end of 1982 with a turnaround thereafter. From the low point starting in 1983, we anticipate a three percent per year increase, the rate at which we believe the OPEC long-term strategy pricing formula would operate if it is adopted by the end of 1982. The net effect of this price forecast is a real price increase of 1.8 percent per year from 1980 to 1987.

It is this projection which we have utilized in this report to test Alaskan gas marketability. The basic crude projection has been adjusted for transportation and other crude oil sources, and then converted into a price series for the refiners' acquisition cost of crude oil. This series has been used in turn to develop both distillate and residual fuel oil prices by region.

In the Natural Gas Policy Act, Congress granted Alaskan gas the right to rolled-in treatment for ratemaking purposes. This was designed to permit price-controlled old gas (which will continue long after 1985 new gas deregulation) to cross-subsidize any portion of the price of Alaskan gas over and above market clearing price levels. In a high oil price scenario, Alaskan gas quickly becomes competitive on the margin, as real oil prices overtake the initially higher-priced Alaskan gas. In our least unlikely combination of oil and gas prices, Alaskan gas requires little roll-in treatment during the early years to be marketable.

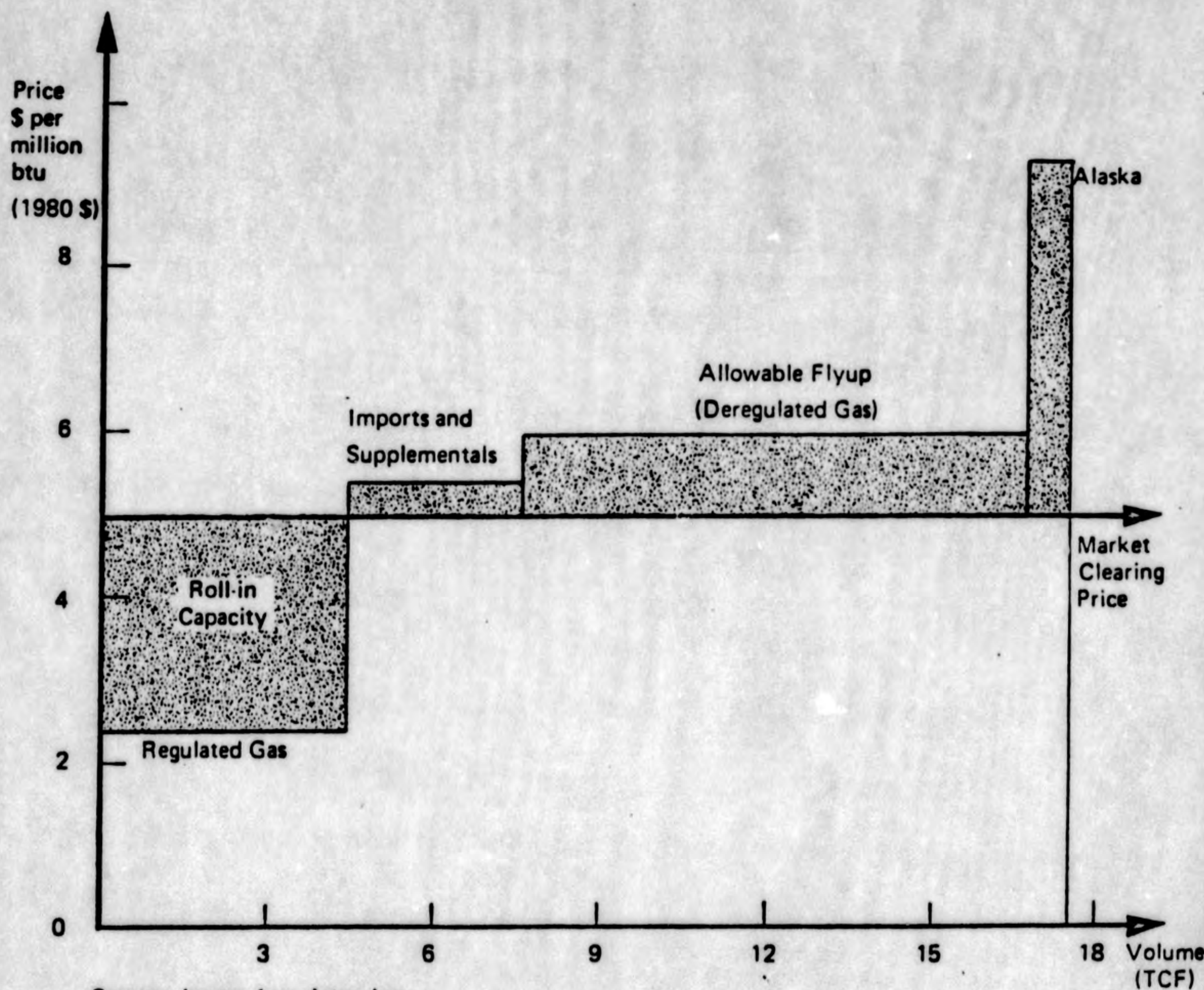
However, in our lower bound case, Alaskan gas must rely--in the early years, at least--on some form of price accommodation such as the rolled-in treatment which Congress granted it in the NGPA. We estimate that if the NGPA goes to term, the 1987 market will have 25 percent of total U.S. gas supply still regulated below the market clearing levels, amounting to a roll-in capacity of $11.7 billion. Other supplementary gas supplies, priced above clearing levels, will utilize a portion of this capacity, but most of it remains to accommodate the Alaskan gas and to provide a potential for "flyup"--the rapid market and contractual escalation of deregulated new gas prices in 1985. Figure II illustrates the roll-in capacity numbers for 1987 when the relative prices of Alaskan gas and oil are least favorable.

The extent to which this roll-in capacity will actually be available depends on world oil price levels, the nature of gas price regulation between now and 1985, and the extent to which the gas pipeline industry, through its contracting practices, may lock in enough deregulated gas price escalation to absorb part of this capacity. We have assumed that the individual reselling pipelines would be in the best position to coordinate their gas contracting practices, their markets, and the rolled-in accommodation of Alaskan gas. Indeed, we have seen evidence of just this sort of integrated supply/market planning taking place, and as a result our report concludes that the roll-in capacity will be there for the lower bound case.

The recent debate over early gas deregulation, the turbulence in world oil markets and the response of OPEC, raise legitimate questions as to what would happen to the markets for Alaskan gas if the roll-in capacity is not available as Congress intended. It is important to recognize that the Alaskan price projections utilized throughout our report and illustrated in Figure II are "front-end loaded." The cost-of-service ratemaking approach utilized by U.S. utilities attempts to recover operating costs and a return on undepreciated plant investment in the rates

Figure 11

1987 ROLL-IN CAPACITY OF U.S. NATURAL GAS MARKETS
(Based on Lower Bound Crude Price
and
Upper Bound Alaskan Price)



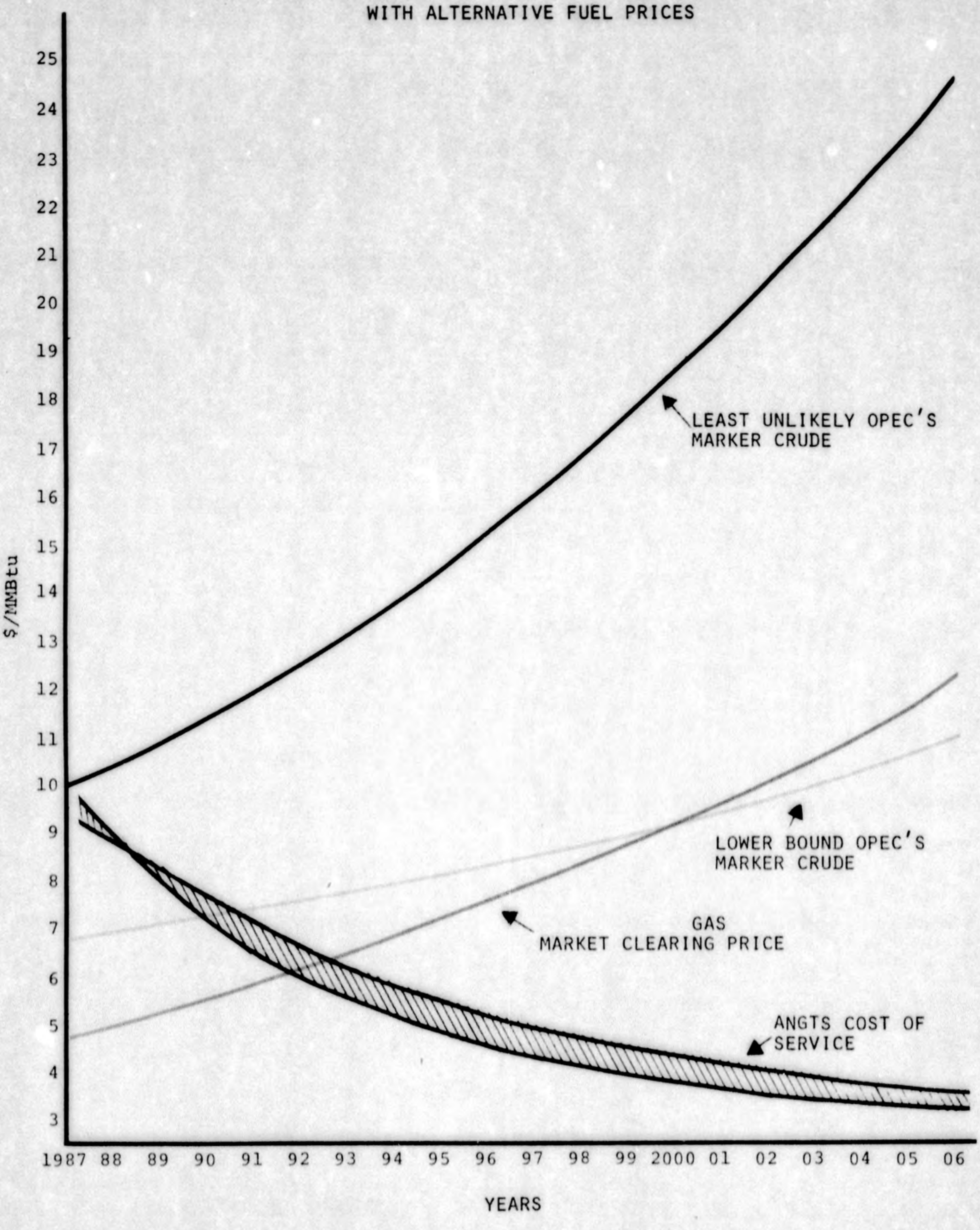
Source: Jensen Associates, Inc.

charged to customers. This makes rates, for a major project such as this one, highest at start-up and declining thereafter as the plant investment is depreciated. In addition, the Congressional preference for price regulation of Alaskan gas at the wellhead represents an abandonment of the more customary "netback" approach to new project wellhead pricing where producers charge no more than what the market will permit during early years, in return for greater pricing flexibility later on. This approach prices gas higher in the early years then it would be priced under the customary netback approach and is thus also front end loaded. By adopting approaches which have the effect of shifting to a more level rate structure over the life of the project, the sponsors have much more flexibility to accommodate those market uncertainties than the schedule of prices which we have utilized in this report might suggest. No one that we know is seriously suggesting that OPEC oil could continue to be cheaper than Alaskan gas over any significant period of project life.

In summary, we believe that a commercial market for Alaskan gas will exist in 1987. Its volumes will be required along with other supplements if natural gas is not to play a significantly reduced role in meeting future U.S. energy demands. In our least unlikely world oil price scenario, Alaskan gas will increasingly be competitive with alternate gas supplies, which will be largely linked to oil. Lower oil price scenarios, such as the lower bound estimate which we have utilized in our report, will require some price accommodation in the early years. Congress has provided for the use of roll-in capacity to help Alaskan gas through the early start-up years, but other pricing approaches such as wellhead netback pricing and changes in pipeline rate design can also be utilized to accommodate the market.

APPENDIX F

COMPARISON OF ANGTS COST OF SERVICE
WITH ALTERNATIVE FUEL PRICES



APPENDIX G

Net National Economic Benefits of the Alaska Natural Gas Transportation System

Prepared for:
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July 1981

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EXHIBITS

Introduction

The Alaska Natural Gas Transportation System (ANGTS) is the largest privately financed project ever to be considered. Its completion will generate enormous net national benefits. The present value of the Alaskan gas that ANGTS will bring to the United States is likely to be between $90 and $140 billion.* The total present cost of delivering this gas (including the wellhead cost of the gas) is approximately $50 billion over the 25-year project life. Accordingly, the present value of the net benefits of ANGTS is between $40 and $90 billion for all U.S. parties associated with the project. For our base case, we use the median gas value of $110 billion, which yields a median NNEB of $60 billion. All of the above values are in January 1980 dollars, discounted in real terms at 3 percent to mid-1981.

The parties associated with ANGTS include the consumers, the state and federal governments, and the project investors. The benefits will provide the project investors with returns sufficient to attract their respective investments. Additionally, the governments will receive benefits in the form of tax receipts.

In September 1977, President Carter rendered a decision that the Northwest Alaskan Pipeline Company be designated to construct and operate those portions of the ANGTS within the State of Alaska.** Because project

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* These values are the mode and expected value for the gas value, respectively.

** Executive Office of the President, Energy Policy and Planning, Decision and Report to Congress on the Alaska Natural Gas Transportation System (September 1977). Hereinafter cited as the Decision. Northwest Alaskan Pipeline Company is the operating partner for the consortium (Alaskan Northwest Natural Gas Transportation Company) presently sponsoring the Alaskan segment of ANGTS.

cost estimates have changed substantially since the Decision, the project sponsors must demonstrate that the project is still in the public interest.*

Accordingly, Northwest Alaskan Pipeline Company asked Resource Planning Associates, Inc. (RPA), to independently assess the net national economic benefits (NNEB) of ANGTS. Northwest Alaskan Pipeline Company provided the project cost assumptions for the analysis. RPA conducted the analysis of the NNEB and we present our findings in this report. First, however, we define the NNEB and explain the report organization.

DEFINITION OF NET NATIONAL ECONOMIC BENEFITS

Net national economic benefits of a project are simply the economic costs subtracted from the economic benefits. As shown in Exhibit 1, the total costs of the delivered gas are the sum of two major cost categories: the project capital costs and the project annual costs. The latter consist mainly of the price of the gas at the wellhead. The gas is valued at the wellhead for the annual cost calculation. The benefits of the gas derive from the market value of the gas.**

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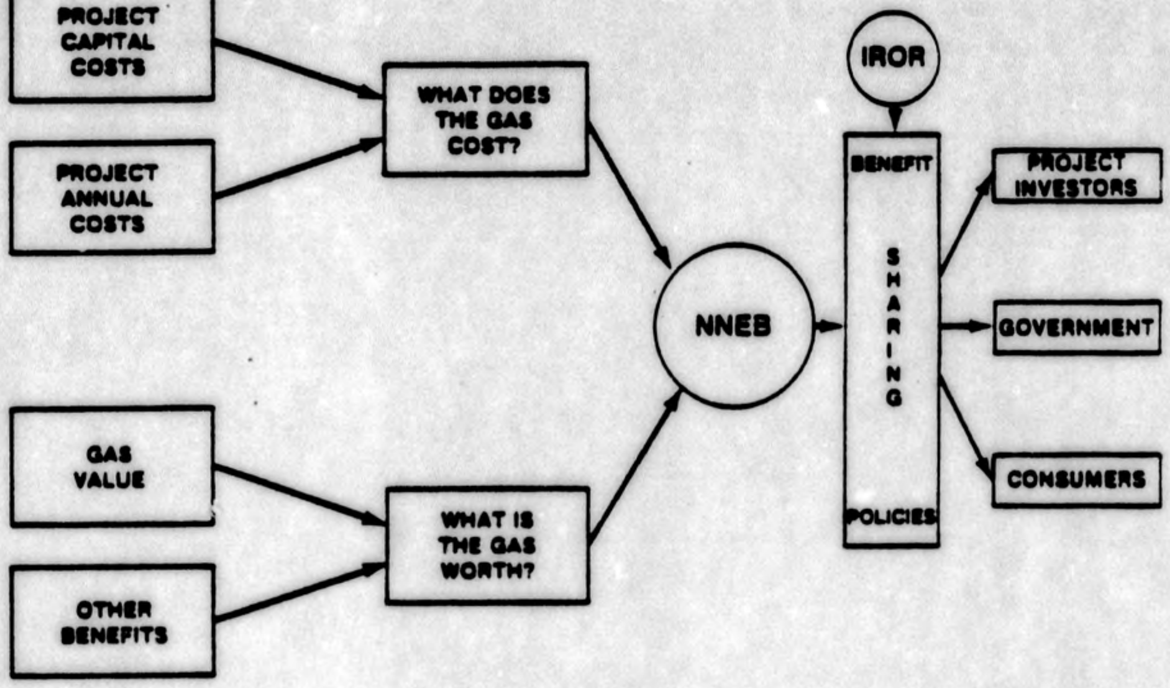
* Order No. 31, "Order Setting Values for the Incentive Rate of Return, Establishing Inflation Adjustment and Change in Scope Procedures, and Determining Applicable Tariff Provisions," Docket No. RM78-12 (June 8, 1979), p. 53.

** Our evaluation excludes indirect benefits, such as increased energy independence, improved balance of payments, and more jobs. Consequently, our estimate of the value of the gas is conservative.

Exhibit 1

NNEB OVERVIEW



The time patterns for the costs and benefits of ANGTS are significantly different. The capital costs are incurred prior to gas flow, whereas the benefits accrue over a minimum 25-year project life. Therefore, the NNEB is largely a matter of society's time value of capital. In our analysis, we used a 3 percent real discount rate for the base case assumption. With an inflation rate assumption of 11 percent, the annual discount rate is 14 percent.

As shown in Exhibit 1, the NNEB is the total value available for sharing among project investors, government, participants, and consumers. The relative shares are determined by project costs, market factors, laws and regulations (such as the Federal Energy Regulatory Commission's incentive rate of return mechanism), and tax policies.

REPORT ORGANIZATION

This report is divided into three parts. In Chapter 1, we present the value of the gas to be delivered by ANGTS. We used an approach that combines the judgment of 28 nationally recognized energy experts to show that the value of the gas is large under all reasonable circumstances. Chapter 2 presents the capital and annual costs for the project, as provided by Northwest Alaskan Pipeline Company. Chapter 3 combines the results of Chapters 1 and 2; in it we elaborate on our definition of NNEB and examine the sensitivity of the base case to changes in several major assumptions. We also demonstrate that the NNEB is large under all reasonable circumstances.

1 THE VALUE OF ANGTS GAS

The value of the delivered Alaskan gas is a major determinant of the NNEB. It is also the most difficult factor to predict, due to its heavy dependence on highly uncertain future energy prices. Consequently, we devoted a major effort in the NNEB analysis to this area. This effort involved utilizing the judgments of a broad cross-section of nationally recognized energy experts.

We define the value of delivered Alaskan gas as the wholesale revenue it could command at the pipeline termini -- that is, at the Chicago and San Francisco region gateways* -- in an unregulated environment. This is equivalent to the wholesale cost of fuels that would be consumed in the absence of Alaskan gas, approximately adjusted for differences in the costs of local distribution and end-use utilization. In Chapter 3, we explain the use of gas value, thus defined, in calculating the NNEB.

To account for the high degree of uncertainty in the future value of Alaskan gas, we interviewed 28 nationally recognized experts on future energy prices. These interviews were conducted during the first quarter of 1981. These experts and their affiliations are listed in Exhibit 1.a. The combined results of our interviews are summarized as a probability distribution in Exhibit 1.b. On a levelized basis, the median gas value is $9.17 per million Btu in 1980 dollars. The expected value is $11.79 and the mode (most likely) is $7.50. The probability of a value less than $4.94 is 10 percent, as is the probability of a value greater than $18.32.

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* A small amount of Alaskan gas is also delivered within the State of Alaska. This is included in our definition of the value of ANGTS gas.

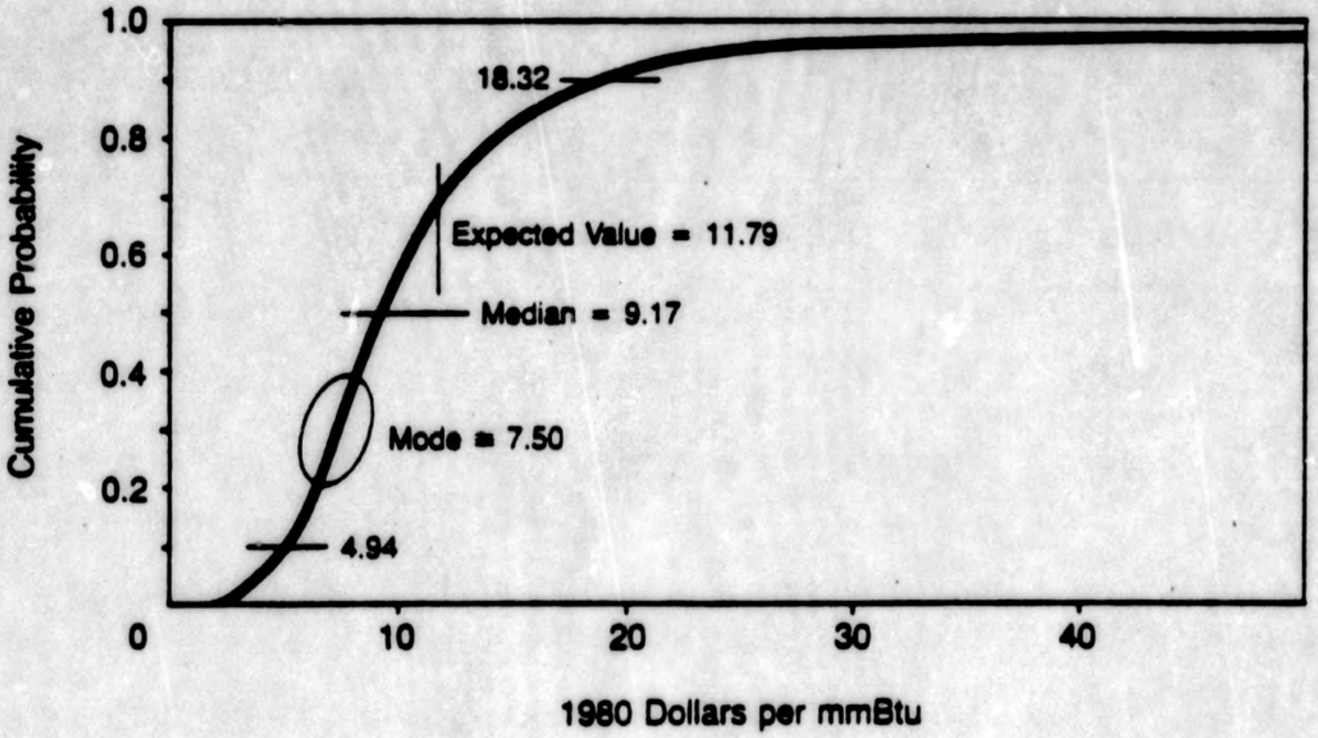
Exhibit 1.a

PARTICIPANTS IN ANALYSIS OF THE VALUE OF ALASKAN GAS

Expert	Affiliation
Alvin Alm	Harvard University
Michael Barron	Department of Energy
Kenneth Darrow	Gas Research Institute
John Ecklund	Central Intelligence Agency
Robert Fri	Energy Transition Corporation
J. Michael Gallagher	Bechtel
Dermot Gately	New York University
John Gault	Jensen Associates
Roger Glassey	University of California, Berkeley
Eugene Harless	SRI International
Patrick Henry	Booz, Allen, and Hamilton, Inc.
Charles Hitch	University of California, Berkeley
Larry Jacobsen	Federal Reserve Board
Michael Kennedy	University of Texas
John Lichtblau	Petroleum Industry Research Foundation, Inc.
Henry Linden	Gas Research Institute
Rene Males	Electric Power Research Institute
Ted Moran	Georgetown University
Roger Naill	Department of Energy
Richard Nehring	Rand Corporation
Dale Nesbitt	Decision Focus, Inc.
David Nissen	Chase Manhattan Bank
Warner North	Decision Focus, Inc.
James Plummer	Electric Power Research Institute
James Reddington	Department of State
Benjamin Schlesinger	American Gas Association
John Stanley-Miller	Department of Energy
James Sweeney	Stanford University

Exhibit 1.b

COMPOSITE DISTRIBUTION ON THE ANNUITY EQUIVALENT VALUE OF NATURAL GAS



For our base case, we assume the delivered volume of gas to be approximately 2 billion cubic feet per day, beginning in late 1986 and continuing for 25 years. This is the flow rate already authorized by the State of Alaska, and sufficient gas reserves have been proven to assure its feasibility.

Using the assumptions described above, the median present (mid-1981) value of the gas is $110 billion in 1980 dollars. The mode and mean values of the gas are $90 and $140 billion, respectively.

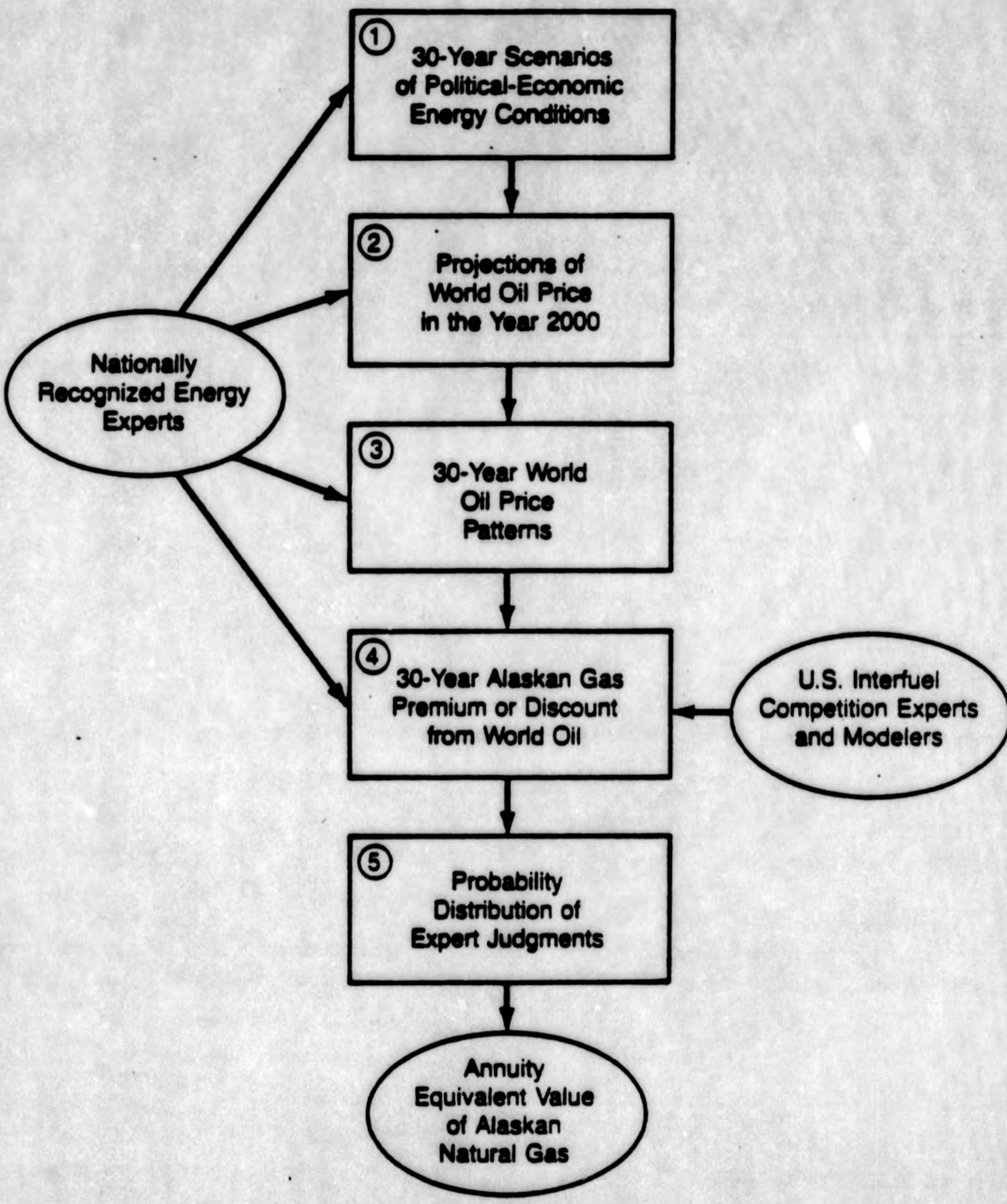
To derive the value of Alaskan gas, we employed the five-step process depicted in Exhibit 1.c. First, the range of possible settings for energy prices was considered by constructing 30-year scenarios of political-economic energy conditions. Second, based on these conditions, a probability distribution on world oil price in the year 2000 was assessed. Third, five 30-year world oil price scenarios were constructed, each corresponding to a price in the year 2000 sampled from the distribution. Fourth, for each world oil price scenario, three gas value scenarios were assessed. Fifth and finally, probability distributions on the levelized value of Alaskan gas were calculated based on the assessments obtained in the previous steps. Each step is further explained below.

Step 1: Develop Scenarios

During our interviews with individual experts, a series of 30-year scenarios was developed. The scenarios included the experts' assumptions about the most influential factors on general world oil price levels. Typically, the experts considered world economic growth, geopolitical pressures and events (particularly in the Middle East), technological developments, governmental policies, and supply and demand elasticities. They developed at least three scenarios -- a likely scenario, a high energy price scenario, and a low energy price scenario.

Exhibit 1.c

FIVE-STEP APPROACH TO ESTIMATING VALUE OF ALASKAN NATURAL GAS



To illustrate, low-price scenarios were characterized by many experts as involving a stable Middle East and rapid technological development and/or depression in most industrialized countries and high elasticity of demand. High-price scenarios were generally characterized by international strife, slow technological progress, and environmental barriers to resource development.

Step 2: Estimate World Oil Price in the Year 2000

For each of the scenarios defined in Step 1, the experts then developed estimates of world oil price in the year 2000. These estimates for each scenario were made as probability statements to capture the experts' degree of confidence. For example, one expert stated: "Given the low-price scenario, we have one chance in ten that no real growth in oil price will take place."

Using these results, and also considering implicitly the multitude of other scenarios that could unfold, the experts then developed an overall probability distribution on world oil price in the year 2000. Exhibit 1.d shows the result for an expert who believes there is a 10 percent chance that the price will exceed $114 per barrel in 1980 dollars and a 10 percent chance that it will be less than $53 per barrel. This expert also considers it equally likely that the price will be above or below $75 per barrel.

The distributions for all 28 experts are overlaid in Exhibit 1.e. Not surprisingly, a great divergence of opinion exists among these experts. One said the price will not be less than $150 per barrel, while another contended that it will not be greater than $70 per barrel. This divergence is due to differing opinions about events in the Middle East, oil discoveries, technological progress, synfuels production, coal development, and future societal values.

Exhibit 1.d

EXAMPLE OF ONE EXPERT'S DISTRIBUTION ON THE PRICE OF WORLD OIL IN THE YEAR 2000

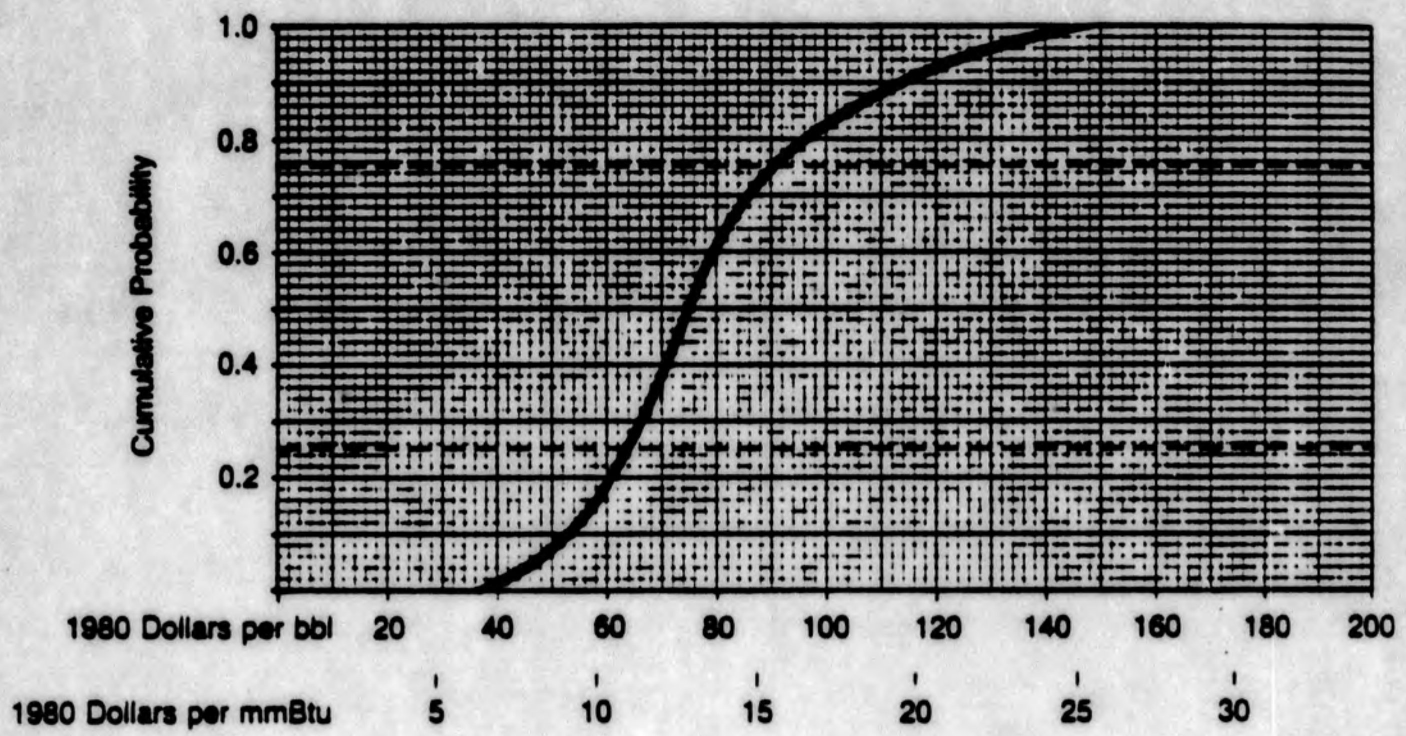
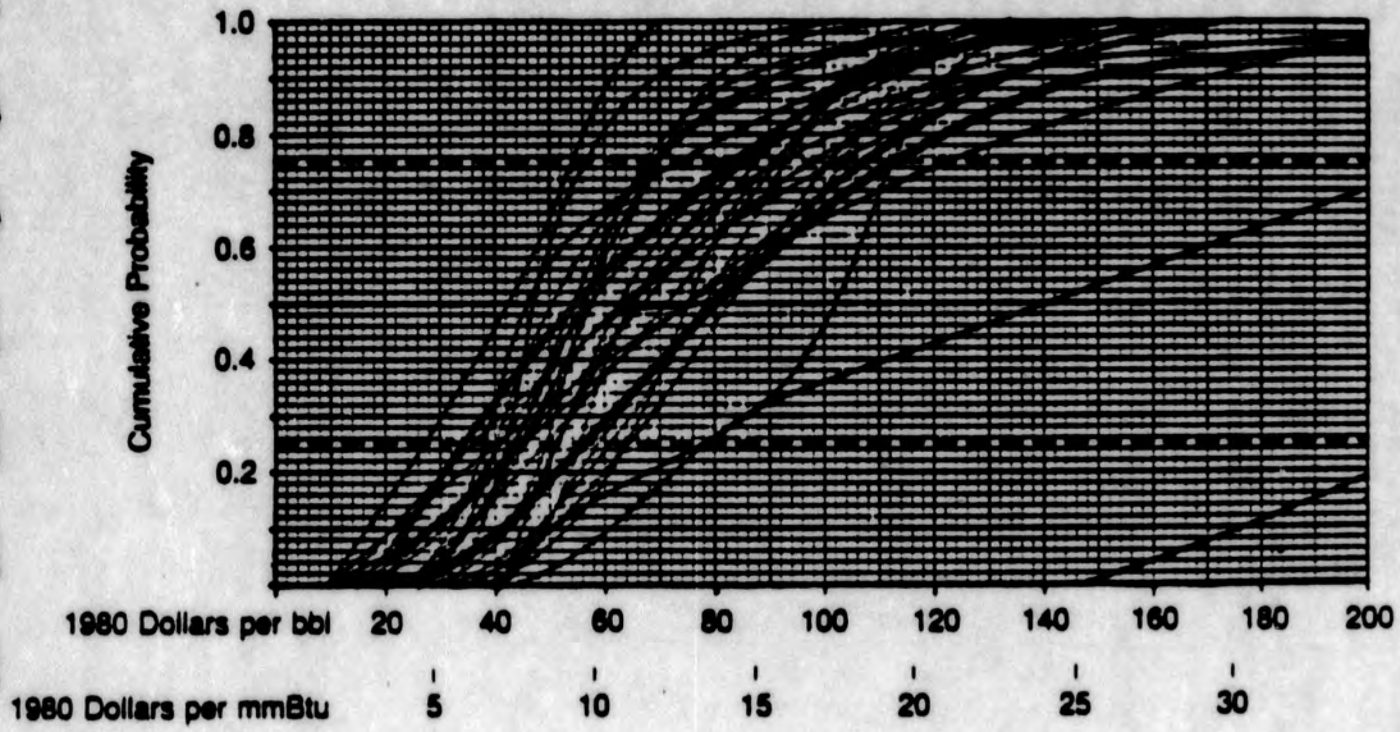


Exhibit 1.e

INDIVIDUAL EXPERTS' AND COMPOSITE
DISTRIBUTIONS ON THE PRICE OF WORLD
OIL IN THE YEAR 2000



The collective judgment of all experts, giving equal weight to each opinion, results in a price ranging from $22 to more than $200 per barrel, with an expected value of $96 per barrel. We can safely say that the experts consider long-term energy prices extremely uncertain. Consequently, any single point estimate is of questionable worth to decision makers.

Most experts were optimistic about the ability of the world economy to cope with less oil. To support this view, they pointed to the relatively minor effect of the loss of Iraqi and Iranian production over the last year. Some, however, considered the world economy less resilient and thought that reduced oil supply combined with higher prices would cause a deep, prolonged world depression. This economic chaos could lead to very low oil prices in the long term. These experts also thought that high oil prices would cause rapid substitution away from oil and gas, thus lowering oil prices.

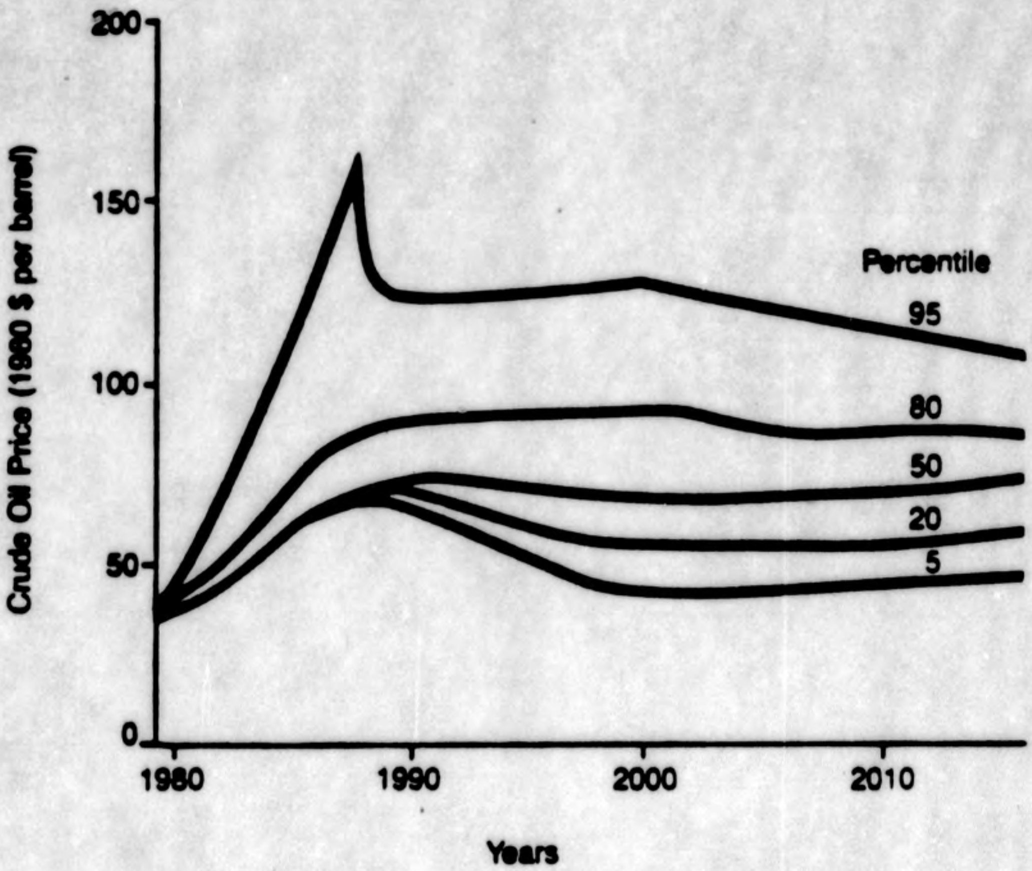
Several experts believe that world oil prices would develop along one of two equally likely scenarios. One scenario is a benign and stable Middle East with relatively high oil production. The other is a turbulent Middle East with major export production shortfalls. The result is a probability distribution on world oil price in the year 2000 that is a composite of two very different distributions, one for each scenario.

Step 3: Assess World Oil Price Patterns

In this step, we extended the results of the previous step to cover the entire period between 1980 and 2010. First, we chose five representative prices from the distribution on world oil price in the year 2000. Then, the experts developed a 30-year time pattern of oil prices consistent with each of these prices. If experts felt that significantly different patterns could be consistent with a single price, they were asked to assess a "weighted average pattern." An example of an expert's price patterns is presented in Exhibit 1.f.

Exhibit 1.f

EXAMPLE OF ONE EXPERT'S
30-YEAR WORLD OIL PRICE PATTERNS



Opinions about time patterns for world oil prices also varied considerably. However, most experts felt that prices would increase substantially and that most of this increase would occur between now and the year 2000, with a slow increase or decline beyond the year 2000. This pattern was explained in several ways. First, experts anticipated that new and more efficient energy production and utilization technologies would emerge by the year 2000, thus halting the rise in oil prices. Second, many experts believed that at least one major disruption in the world oil market would occur before the year 2000. However, there were three points of view as to the effect of this disruption on oil prices. Most experts expected that the price would jump and then remain nearly constant until the long term trend caught up, or until there was another disruption. A few foresaw a temporary surge in prices, followed by a return to the trend. And one anticipated that a surge would later cause the price to fall below the trend line.

In addition to these general patterns, two unique forecasts are noteworthy. One expert envisioned a possible future in which the Organization for Economic Cooperation and Development (OECD) would abandon conservation and new technologies and would later be caught unprepared by the price increases of the Organization of Petroleum Exporting Countries (OPEC). In this scenario, OPEC would adopt a benign pricing strategy for the next ten years. This period would be marked by slowly declining world oil prices and followed by aggressively coordinated price hikes, which would result in very high oil prices in the period between 1990 and 2010. Another expert forecasted an attempt by OPEC to achieve a major price increase in the early 1980s, which would prompt extreme reactions by the consuming nations (e.g., mandatory conservation measures or military intervention in the Middle East). After the reaction, demand would drop sharply, OPEC would collapse, and world oil prices would fall accordingly.

Step 4:
Estimate Gas Value Scenarios

For each of the world oil price patterns developed in Step 3, the experts were asked to consider the premium or discount that gas could command in the unregulated U.S. energy markets. The experts considered the factors that may cause gas to be valued above or below oil on an equivalent-Btu basis. These factors include the cost of fuel conversion, long-term supply and demand situations, air quality standards, and other regulations affecting energy use.

Each expert developed three gas value estimates (10 percentile, 50 percentile, and 90 percentile estimates) for each of the five oil price patterns, leading to 15 gas-value patterns. Again, the experts' opinions about the gas value relative to oil price levels varied considerably over the 30-year period. Generally, the different views hinged on the weight given to the premiums for liquids in the transportation sector and the premiums given to cleanliness and efficiency for the gas. Most experts also took into account the future conversion costs from one fuel to the other.

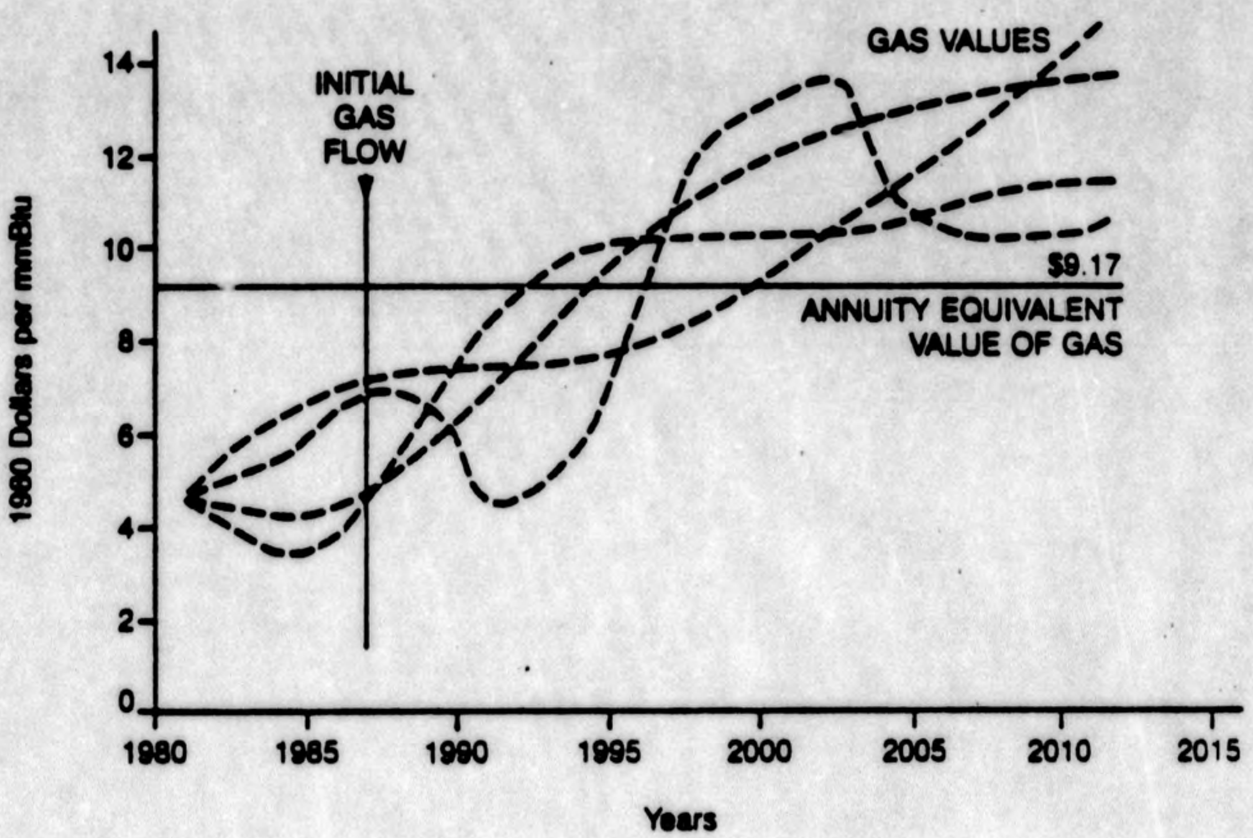
Two camps emerged among the experts: those who considered gas a discounted fuel (especially if oil price level was very high), and those who expected a slight premium for the gas because of its clean-burning characteristics. All experts considered gas value to be linked closely to world oil price.

Step 5:
Develop Probability
Distribution on Gas Value

In the final step, we calculated a probability distribution for each expert on the levelized value of Alaskan gas, as well as a composite distribution. The levelized gas value is a single-number summary of a pattern of values over time. It is a uniform annuity equivalent (i.e., a constant annual value whose present value is the same as a changing pattern). As shown in Exhibit 1.g, a single levelized value may correspond to widely different patterns of values. We chose levelized value as the measure of the value of Alaskan gas for three reasons. First, it can be more readily compared to other energy prices. Second, it can be used to calculate the absolute present value of the gas. Third, it can be represented graphically by a probability distribution.

Exhibit 1.g

RELATIONSHIP BETWEEN GAS-VALUE PATTERNS
AND THE ANNUITY EQUIVALENT VALUE OF GAS



The results obtained in this step are displayed in Exhibit 1.h. The heavy curve is the composite distribution that was obtained by giving each expert equal weight; it is the same as the curve in Exhibit 1.b.

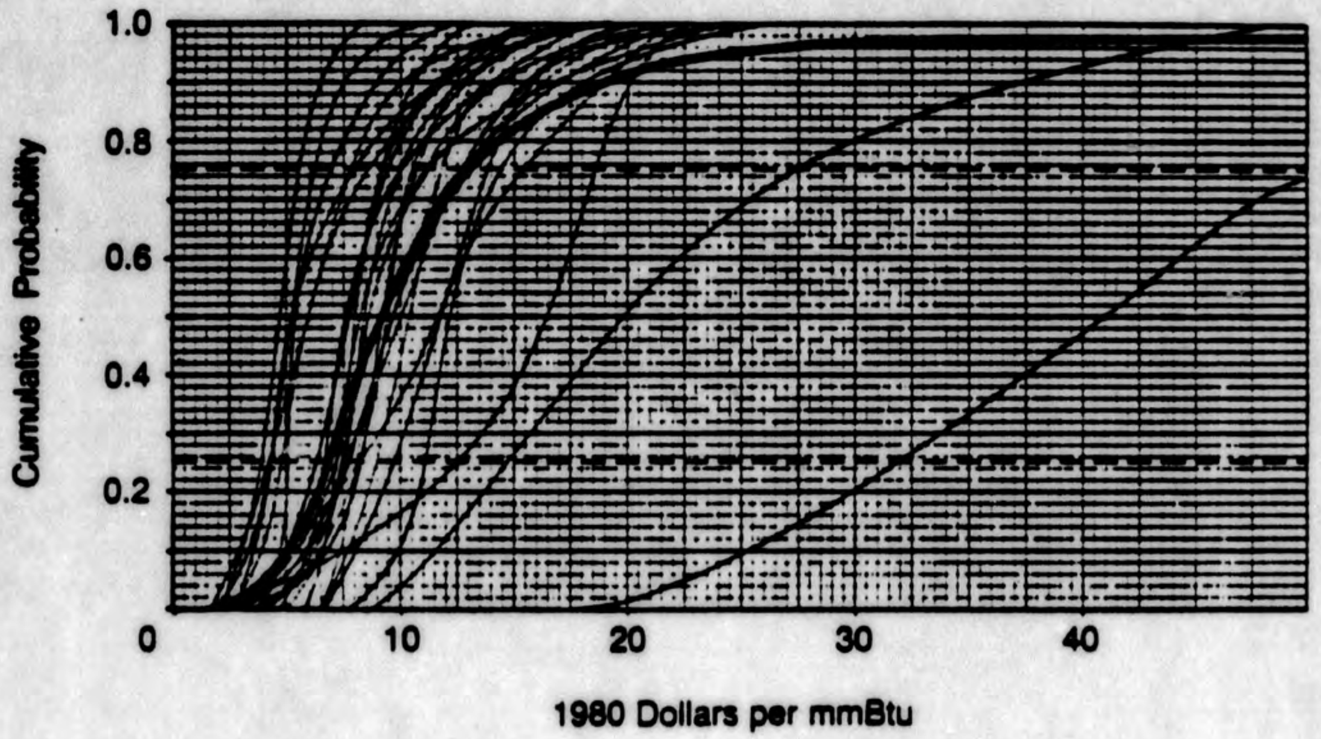
For each expert, the probability distribution on levelized gas value was calculated as follows:

- Each of the 15 gas-value patterns (three for each of the five world oil price patterns) was converted to a levelized value.
- Probabilities were approximated for each of these values, based on the assessments of Steps 2 and 4.
- The distribution was constructed from the probability-value pairs.

The collective judgment was the gas value used for the NNEB analysis presented in Chapter 3. The median value annuity equivalent of $9.17 per million Btu was used for the base case. Given that the gas value distribution is highly skewed upward with an expected value of $11.79 per million Btu, this assumption is conservative.

Exhibit 1.h

INDIVIDUAL EXPERTS' AND COMPOSITE
DISTRIBUTIONS ON THE ANNUITY EQUIVALENT
VALUE OF NATURAL GAS



2 ANGTS COSTS

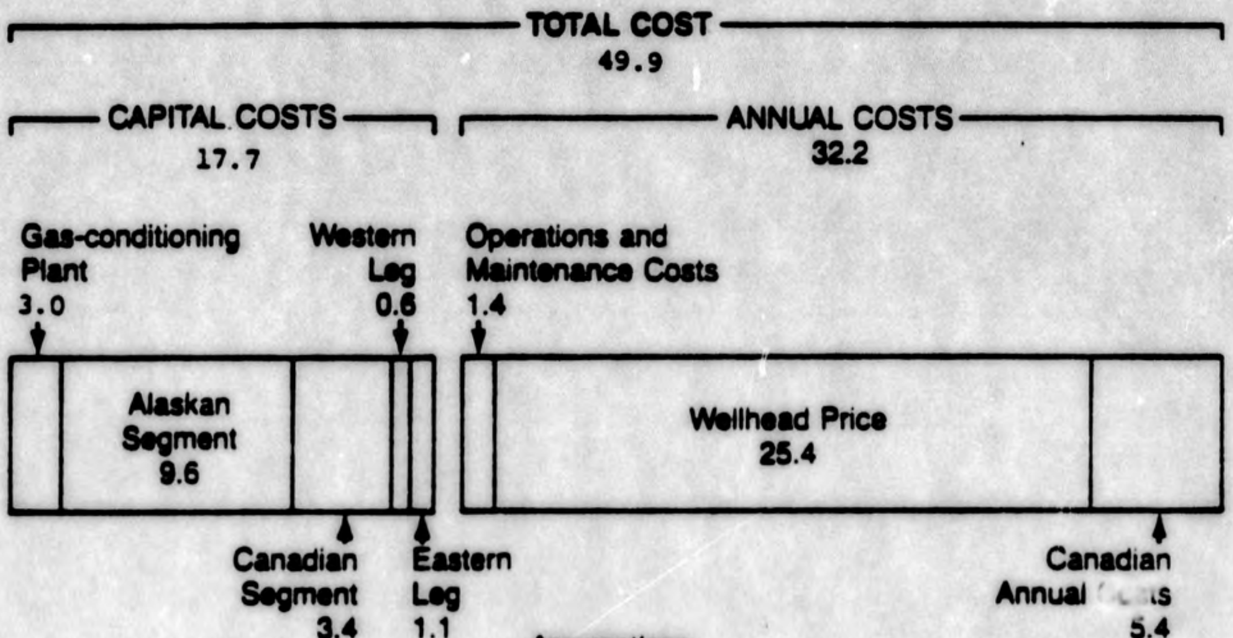
ANGTS is composed of a gas-conditioning facility at Prudhoe Bay and several major pipeline segments that ultimately deliver gas near Chicago and San Francisco. The total cost of delivering the gas to the U.S. consumers is $73 billion in 1980 dollars. This includes the cost of the natural gas at the wellhead, the capital costs of facilities to condition and transport Alaskan gas, the operating and maintenance costs, and Canadian annual costs. It does not include inflation, financing charges, or the incentive rate of return rate base adjustment. Discounted at a 3 percent real discount rate, the total mid-1981 present value cost is approximately $50 billion in 1980 dollars. The components of this cost are illustrated in Exhibit 2.a. In this chapter, we present the estimates of the capital and annual costs of ANGTS as provided to RPA by the Northwest Alaskan Pipeline Company.

CAPITAL COSTS

The gas-conditioning facility, the Alaskan segment of the pipeline, and the northern portion of the Canadian segment must be built solely to prepare and transport the natural gas produced at Prudhoe Bay. The southern portion of the Canadian segment and the U.S. Eastern and Western segments of the pipeline will transport both Alaskan and Canadian gas. The combined capital costs attributable to conditioning and delivering Alaskan gas add up to $19.5 billion in 1980 dollars. Discounted at 3 percent, the present value of these costs is $17.7 billion. Capital costs represent 34 percent of the total cost to be borne by the United States. They are explained individually below.

Exhibit 2.a

COMPONENTS OF THE TOTAL COST OF DELIVERED GAS (1980 $ billions present value)



Assumptions:

NGPA Wellhead Price (including 10% Alaskan severance tax).
No Design and Scope Changes.
No Regulatory Delays.
Incremental Capital Costs of Transportation System for Alaskan Gas Only.
Real Discount Rate of 3%.

Gas-Conditioning Facility

A $3.3 billion cost is assumed for the gas-conditioning facility in 1980 dollars. The present value cost is $3.0 billion in 1980 dollars, using a 3 percent real discount rate. This cost represents 17 percent of the capital costs and 6 percent of the total cost of ANGTS.

Alaskan Pipeline Segment

From the gas-conditioning facility at Prudhoe Bay, the Alaskan segment of the pipeline system takes the gas south to Fairbanks and then southeast to the Canadian border. Second to the cost of the gas itself, this segment has the largest cost associated with the project. The capital cost for the Alaskan pipeline segment is $10.6 billion in 1980 dollars. Using a 3 percent real discount rate, the present value of this cost is $9.6 billion. The Alaskan pipeline segment accounts for 54 percent of the ANGTS capital costs and 19 percent of the total cost to be paid by the United States for Alaskan gas deliveries.

Canadian Pipeline Segments

From the Alaskan border, the gas is transported southeast through Canada to the United States. The cost of the Canadian pipeline segments is approximately $5.8 billion in 1980 dollars. However, some of the pipeline capacity will be devoted to carrying Canadian gas. Of the 1179.9 trillion cubic feet per year to be delivered through ANGTS in the Lower-48 states, 406.4 trillion cubic feet (or 34 percent) will be Canadian gas. Accordingly, approximately 34 percent of the Canadian portion of ANGTS is devoted to Canadian gas transportation. The capital cost attributable to Alaskan gas is therefore $3.8 billion in 1980 dollars. Discounted at 3 percent, the present value of the Canadian capital cost required to transport Alaskan gas is $3.4 billion in 1980 dollars. The cost of the Canadian pipeline segments is 19 percent of the capital costs and 7 percent of the total cost to the United States.

Lower-48 Pipeline Segments

Near Caroline, Alberta, the Canadian pipeline bifurcates. One segment travels southeast to the Chicago area and the other travels southwest to the San Francisco area. Both of these pipelines will be carrying Canadian gas before the Alaskan flow begins in late 1986. Once Alaskan flow begins, the Eastern and Western segments will carry approximately 64 and 70 percent Alaskan gas, respectively. Of the $1.8 billion total cost in 1980 dollars of the U.S. Eastern segment, $1.2 billion is attributable to Alaskan gas. Of the $0.8 billion total cost in 1980 dollars of the U.S. Western segment, $0.6 billion is attributable to Alaskan gas. Taken together and discounted with a 3 percent real discount rate, the present value of the cost of these segments is $1.7 billion in 1980 dollars. The Lower-48 pipeline segments account for 10 percent of the capital costs and only 3.4 percent of the total cost to be borne by the United States.

ANNUAL COSTS

The annual costs include the cost of the natural gas itself, ANGTS operating and maintenance costs, and the Canadian cost of service. These costs amount to $57.3 billion in 1980 dollars. Discounted at a 3 percent real rate, the present value of these costs is $32.2 billion. Annual costs represent 65 percent of the total cost for delivered Alaskan gas. They are discussed separately below.

Natural Gas Cost

The natural gas cost at the wellhead is the largest single cost associated with the project. The gas cost is determined by Alaskan severance tax policy, the Natural Gas Policy Act of 1978 (NGPA), and the flow rate into the gas-conditioning facility. Alaska is likely to charge a 10 percent severance tax on the wellhead price of the gas. The NGPA specifically omits Prudhoe Bay gas from deregulation and allows the maximum price of the gas to rise only with inflation. Consequently, the real cost of the gas will not rise as long as the NGPA is in effect. Finally, the assumed input flow rate is 2.1 billion cubic feet per day beginning in late 1986. The natural gas cost amounts to $42.1 billion in 1980 dollars, $22.6 billion greater than all capital costs combined. Using a 3 percent real discount rate, the present value of the natural gas cost at mid-1981 is $25.4 billion in 1980 dollars. At this discount rate, the cost of the gas represents 51 percent of the total cost.

Operating and Maintenance Costs

Operating and maintenance costs for ANGTS, excluding Canada, are $2.4 billion in 1980 dollars. These costs were estimated by weighting the costs for each segment by the proportion of Alaskan gas flowing through the segment. They do not include the cost of the pipeline gas used by compressors at compressor stations, which is recognized only by increasing the cost of gas leaving each segment above the cost of the gas as it entered the segment. The present value of the operating and maintenance costs is $1.4 billion in 1980 dollars, using a 3 percent real discount rate. Using this same discount rate, operating and maintenance costs outside of Canada account for 3 percent of the total cost.

Canadian Annual Costs

Finally, the Canadian annual costs going to the Canadian government and the sponsors of the Canadian segments is approximately $9 billion in 1980 dollars. These costs represent the difference between the Canadian cost of service ($12.8 billion) and the Canadian capital costs ($3.8 billion) and includes Canadian segment operating and maintenance costs (approximately $0.6 billion). Using a 3 percent real discount rate, the present value of the Canadian cost of service is $8.8 and of capital costs is $3.4 billion. Thus, the present value of Canadian annual costs is $5.4 billion in 1980 dollars. These annual costs must be subtracted from NNEB because they are costs paid by U.S. parties.

3 NET NATIONAL ECONOMIC BENEFITS OF ANGTS

In the two preceding chapters, we presented estimates of the value of the Alaskan gas and the cost of the gas and transportation system. In this chapter, we combine value and cost to derive the NNEB of ANGTS. We begin by reviewing the underlying assumptions in the NNEB estimate, including the use of a 3 percent real discount rate. Finally, we examine the sensitivity of the base case to several important assumptions about the project.

Briefly, the base case present value of the NNEB of ANGTS is approximately $60 billion in 1980 dollars, assuming a real discount rate of 3 percent. Although this figure is sensitive to several important variables, none of these variables, within a reasonable range, causes it to be negative. Furthermore, the risks of a lower NNEB are outweighed by the potential of a significantly higher NNEB.

THE BASE CASE

Several government agencies, energy companies, and consultants have estimated the NNEB of ANGTS. All of these studies have used similar methodologies. The most recent study concludes that "the ANGTS project would generate overwhelming net benefits to the nation and to each major project participant, including producers, pipelines, consumers, and government."*

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* Douglas B. Fried and William F. Hederman, Jr., "Benefits of an Alaskan Natural Gas Pipeline," The Energy Journal, Vol. 2, No. 1, pp. 19-36, 1981. The NNEB estimate in this study was $22 billion in mid-1980 dollars, using a 6 percent real discount rate and somewhat lower gas values.

The NNEB is derived by subtracting the costs presented in Chapter 2 from the value of the gas presented in Chapter 1. This procedure yields a combined estimate of cost savings to energy wholesalers and consumers, of government tax receipts, and of returns to project investors.

The $60 billion estimate of the NNEB for the base case is derived as follows:

Components of NNEB	Value ($ billions)
Value of Delivered Gas	110.0
Capital Costs	17.7
Operating and Maintenance Costs	1.4
Wellhead Price	25.4
Canadian Annual Costs	5.4
Total Cost of Gas	49.9
Net National Economic Benefits	60.1

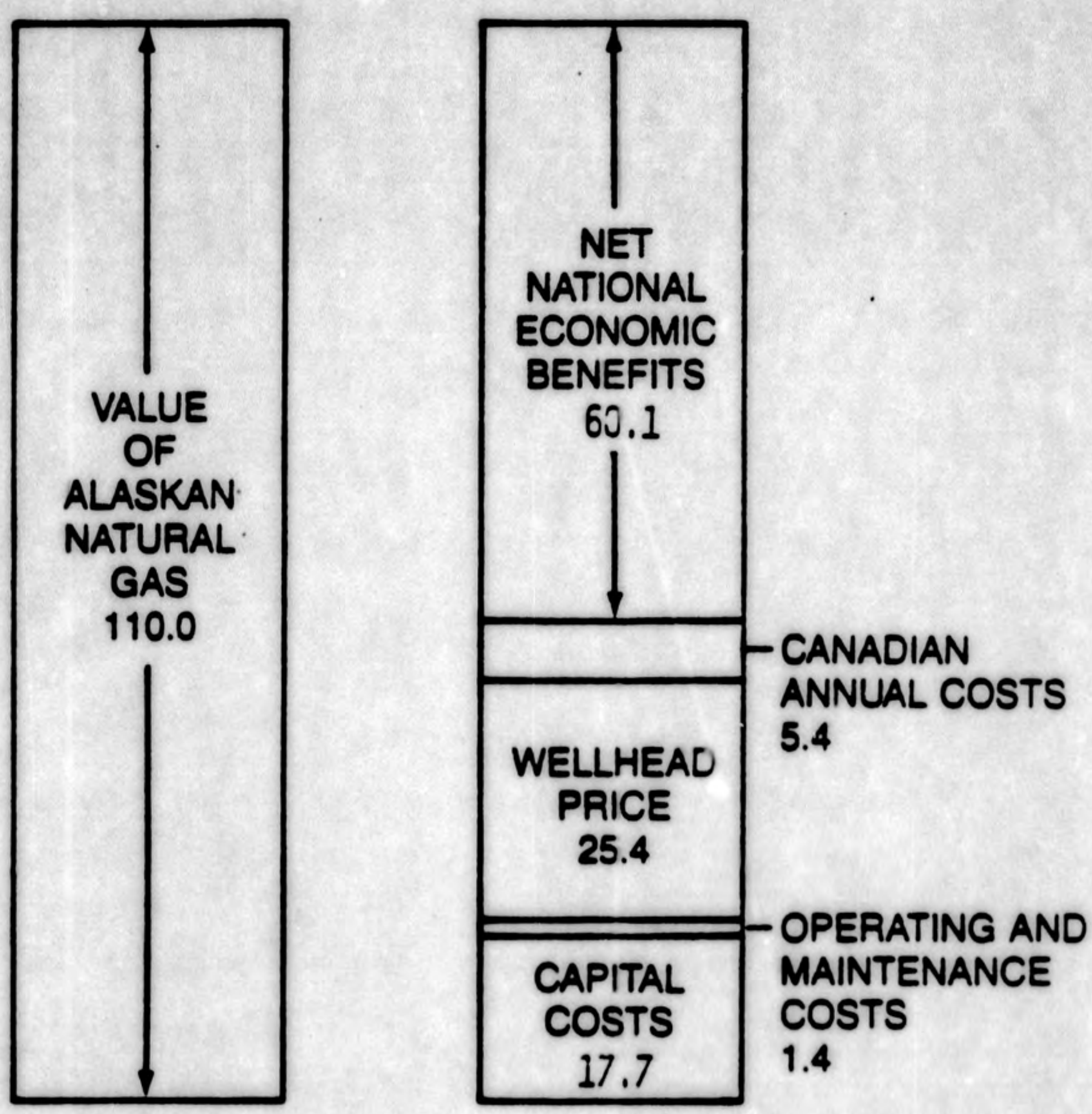
The relative magnitude of these components is displayed in Exhibit 3.a.

This estimate of the NNEB rests on a number of implicit assumptions:

- The gas will ultimately "back out" foreign energy sources or U.S. sources that would have a cost equal to the gas value.
- The gas is valued at the wellhead price before entering the conditioning or transportation system.

Exhibit 3.a

RELATIONSHIP BETWEEN NNEB ESTIMATE
AND VALUE OF ALASKAN NATURAL GAS
(1980 $ billions)



- The availability of the gas does not have a significant impact on overall world energy prices or supply and demand relationships.
- The additional benefits of improved balance of payments and increased energy independence are not included.
- Benefits to contractors and vendors for the construction of the system are ignored.

SENSITIVITY ANALYSIS OF THE BASE CASE

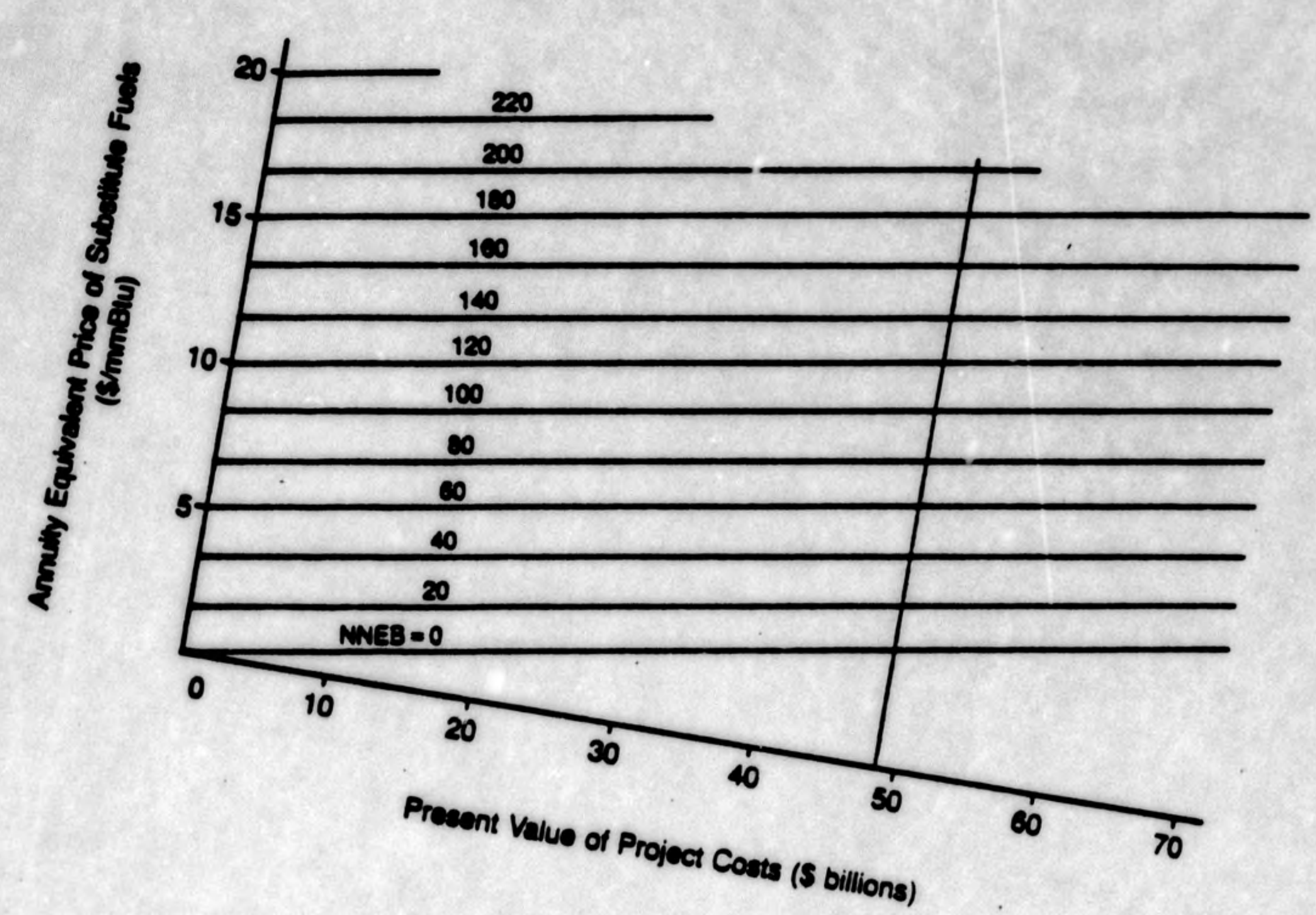
In addition to the above implicit assumptions, the specific assumptions that were made for the base case analysis are highly uncertain. For example, the value of the gas, based on the experts' collective judgment, had one chance in ten of being below $4.94 per million Btu. Moreover, ANGTS is still in an early stage of engineering and its capital costs are not yet definite. Also, if additional reserves are discovered, the delivery volume and the project life could increase significantly.

Beyond these uncertainties, considerable controversy has surrounded the selection of an appropriate discount rate. Briefly, the real rate of return on risk-free private investments such as U.S. Treasury Bills is an upper bound on the appropriate rate. This is because ANGTS will provide a hedge against the risks of present dependence on imported energy. Historically, U.S. Treasury Bills have yielded less than a 3 percent real rate of return.

In Exhibit 3.b, we present the relationship of the NNEB estimate to changes in project cost and gas values. The base case is identified on the graph. Note that a $10 billion increase in project costs could be completely offset by a $0.83 per million Btu increase in gas value. This relationship explains why ANGTS is so attractive today -- even though cost estimates have grown significantly. The doubling of oil prices in late 1979 more than made up for the increase in project cost estimates.

Exhibit 3.b

NNEB FOR DIFFERENT PROJECT COSTS AND GAS VALUES



The degree of uncertainty in gas value and project cost is demonstrated in Exhibit 3.c. As shown, uncertainty in the NNEB ranges from a high of $170 billion to a low of $5 billion. The NNEB corresponding to the modal value of the gas is $40 billion. For the expected gas value, the NNEB is $90 billion.

The other key sensitivities are given in Exhibit 3.d. As evident in this table, the value of the gas is by far the single most important factor. It can increase the NNEB by $110 billion or decrease it by $51 billion. Changes in the U.S. project cost have a dollar for dollar effect on the NNEB. However, even major changes in costs claim only a small fraction of the NNEB.

Although a higher discount rate does not seem justified, the NNEB is clearly sensitive to the discount rate assumption. A higher discount rate decreases the value of future energy cost savings and therefore reduces the NNEB signficantly. The present value of project costs also drops, but less since the capital costs are expended much earlier. This relationship is presented in Exhibit 3.e. Even at the most extreme assumption of a 10 percent real discount rate (above inflation), the NNEB exceeds $13 billion.

The NNEB analysis was performed in real 1980 dollars. Changes in inflation rate assumptions would have no effect on the NNEB value.

Exhibit 3.c

NNEB OVER EXTREME RANGES OF PROJECT COSTS AND GAS VALUE

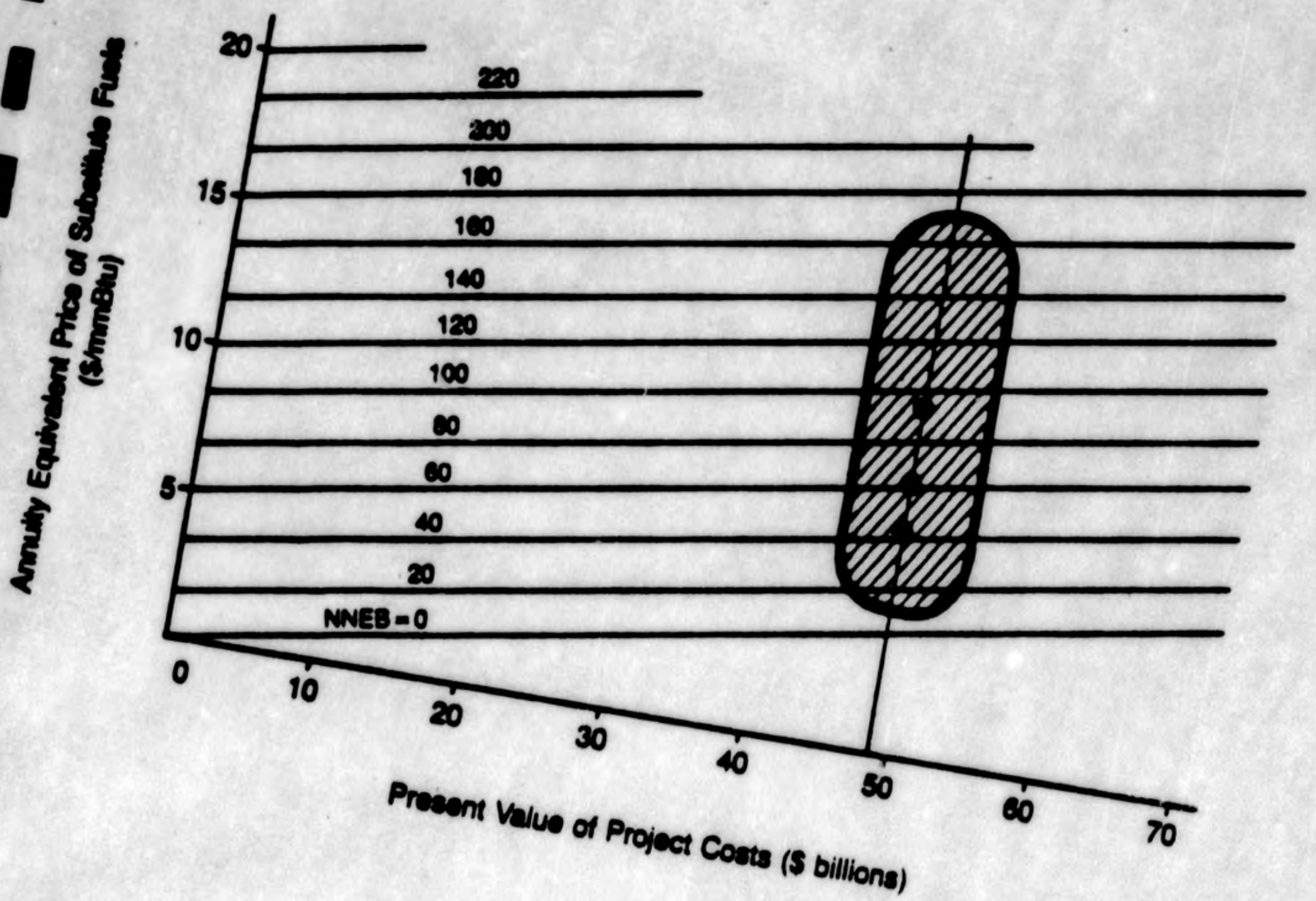


Exhibit 3.d

SENSITIVITY OF NNEB TO
CHANGES IN MAJOR ASSUMPTIONS

Assumption	Sensitivity Scenario			Change in NNEB From Base Scenarios (1980 $ billions)	
	Low	Base[a]	High	Low	High
Value of Gas ($/mmBtu)	4.94	9.17	18.32	-51	+110
Project Cost[b] (1980 $ billions)	55	50	-	-5	-
Real Discount Rate (%)	6	3	-	-29	+54
Project Life (years)		25	50	-	+39

a. Median NNEB of $60 billion.

b. Assumes a 30 percent capital cost increase. Also assumes no increase in Canadian annual costs or taxes as a result of a cost increase.

Exhibit 3.e

SENSITIVITY OF NNEB TO
REAL DISCOUNT RATE
(1980 $ billions)

	Real Discount Rate (%)			
	0	3	6	10
Value of Gas	187.2	110.0	67.9	39.0
Project Costs	-73.0	-49.9	-36.4	-25.9
NNEB	114.2	60.1	31.5	13.1

* Based on median estimate of gas value ($9.17 per mmBtu).

APPENDIX H

JOINT STATEMENT OF INTENTION

June 1980

JOINT STATEMENT OF INTENTION

Atlantic Richfield Company, Exxon Corporation, and The Standard Oil Company (Ohio) (the Producers), and Alaskan Northwest Natural Gas Transportation Company, a partnership (Alaskan Northwest), enter into this Joint Statement of Intention at the request of the United States Department of Energy.

Preliminary Recitals

The Producers and Alaskan Northwest have a common interest in the efficient and cost-effective construction and operation of the Alaska Natural Gas Transportation System (ANGTS) including the conditioning plant at the earliest practicable date. Alaskan Northwest has developed a construction schedule for the ANGTS which would result in completion of the system in 1985.

The facilities to be constructed in the State of Alaska which are necessary to placing the ANGTS in service require immense capital investment, and private sector lenders who will be asked to advance funds for the construction of Alaskan facilities will require reasonable assurance that the facilities will be completed and placed in service, and their debt serviced.

The President's Decision and Report to Congress describes the plan for private financing of the ANGTS to be implemented by Alaskan Northwest. Alaskan Northwest has indicated that the Alaskan segment of ANGTS can be financed in the private sector, if there is meaningful participation by the Producers in the financing structure. The Producers have indicated willingness to participate in a substantial way with Alaskan Northwest in the financing of the Alaskan pipeline and conditioning plant upon reasonable terms and conditions, provided they are not placed in the position of becoming, in effect, the ultimate guarantors of completion of the ANGTS and provided that their financial exposure is effectively limited.

In an effort to move forward in surmounting the acknowledged difficulties presented by this project, the parties have entered into a Cooperative Agreement for continued design and engineering of the Alaskan gas pipeline and the conditioning plant which will prepare natural gas produced from the Prudhoe Bay unit of Alaska for transmission through ANGTS.

Statement of Intention

It is the mutual objective of the Producers and Alaskan Northwest that the ANGTS be completed and placed in service at the earliest practicable date and, accordingly, the Producers and Alaskan Northwest intend to use their best efforts, on a joint and cooperative basis, to expedite design, engineering and cost estimation.

The Producers, together with their advisers, will work with Alaskan Northwest in an effort to develop its financing plan in such time and manner so that necessary governmental approvals may be obtained and construction commenced and completed as scheduled by Alaskan Northwest.

It is recognized that in order for the financing plan to be acceptable to the financial community the project must be economically sound and the financing plan must accommodate reasonably desired protections for the interests of potential lenders. If the parties, or any of them, conclude that alternate approaches in financing, or waivers of law under the Alaskan Natural Gas Transportation Act are necessary to effectuate a feasible and effective plan of financing, such party or parties may develop alternatives and advise appropriate authorities of their conclusions.

This Statement of Intention shall be signed after approval hereof by the Department of Energy.

IN WITNESS WHEREOF, the parties have executed this 19th day of June, 1980.

Alaskan Northwest Natural Gas Transportation Company, Acting By and Through its "Operator", Northwest Alaskan Pipeline Company

By John G McMillian

Atlantic Richfield Company

By [signature]

Exxon Corporation

By [signature]

The Standard Oil Company (Ohio)

By [signature]

APPENDIX I

August 28, 1981

Mr. John G. McMillian
Chairman & Chief Executive Officer
Northwest Alaskan Pipeline Company
P. O. Box 1526
Salt Lake City, UT 84111

Dear Mr. McMillian:

In our letter of June 18, 1981, submitting our proposal to assist you in structuring financing for the Alaska Segment of the Alaska Natural Gas Transportation System (ANGTS) (the "Project"), we (the "Banks") indicated that, in the first phase of our work, we would complete a preliminary review of capital markets and funding sources for the Project and present to you our initial assessment, not only of the amounts, but also of the basic terms on which we believe funds from these sources might be available. We also undertook to develop an approach to reviewing the technical and marketing aspects of the Project and to determine how we could obtain satisfactory access to a financial model to assist us in analyzing the financing plan.

On August 6, 1981 we wrote to you to report on the first phase of our work. In subsequent conversations you asked for certain clarifications and amplifications of statements in that letter. In response, we are submitting this letter which replaces and supercedes our earlier letter.

We have conducted our investigations and analysis on the basis of information furnished by you, contained in the presentations you gave to each of the Banks in late May, the Project Overview you supplied to each of the Banks at that time, your letter to Exxon, Sohio, and Arco (the "Producers") dated May 21, 1981 outlining the terms of the pipeline sponsors' (the "Sponsors") agreement with the Producers, a number of financial cases prepared by the Sponsors, and information you provided in connection with certain legislative waivers in order to facilitate financing and construction of the Project.

Concurrently with this phase of our work we have been considering the legislative waivers. We wrote to you on this subject on June 3, 1981, and on July 14, 1981 we made available to you a memorandum which was distributed to a number of Administration officials and Congressional staff. We continue to support the views expressed in those communications, and would emphasize the need for a flexible approach to "billing commencement" until a more definite financing plan is developed.

The principal focus of our efforts to date has been to address the funding availability and related credit aspects of the Project, and this letter deals almost entirely with these subjects. However, a few brief comments are also included on the work of our task forces which have been addressing the issues of Gas Marketability, Engineering, and Financial Modeling. These groups have been developing approaches to their respective aspects of the Project to be pursued in detail in subsequent phases of our work. While the scope of their work is more appropriately covered in a later proposal dealing with parameters and premises that should govern the next phase of our work, several of their conclusions are relevant to this report and form Appendix A.

Inter-Relationship of ANGTS Segments

One tariff pay all

We were asked to focus our analysis of the Project on the Sponsors' share of the financing for the Alaska Segment. However, upon reflection, it became apparent to us that it would be necessary to broaden our consideration to take into account the impact on the capital markets of the aggregate financing requirements of both the Sponsors and Producers in Alaska as well as the financing requirements for the overall ANGTS project, including Canada and the "lower 48".

a) We understand that it is the intent of both the Sponsors and Producers that, after completion, all financing for the Alaska Segment is to rely on a common source of repayment, i.e. the tariff arrangements. Therefore, we could not ignore the Producers' share of the Financing for the Alaska Segment and did not attempt to consider separate and discrete financings for the Sponsors and Producers.

b) Since, to the best of our knowledge, the post-completion sources of repayment for the Alaska Segment, the financing of the expansion of the "lower 48" facilities and the refinancing of the prebuilt segments will rely on common payment arrangements through the tariffs, we expect that lenders would consider those financings one credit for risk and funding allocation purposes.

c) While the Canadian segment will have available to it additional Canadian loan sources, there is a substantial overlap both in the available funding sources and in the risks, given that all segments rely on related tariffs.

Funding Availability Study

Appendix B contains our initial assessment of funds availability, together with preliminary indications of the basic terms on which funds might be made available for the Project. Although our estimates are based on conversations with a relatively small number of potential lenders, the results conform with our own views and we believe are an accurate reflection of availability of funds in world capital markets under current market conditions.

For reasons described below, the review was undertaken on the basis that the loans would be the risk equivalent of debt with an A/Baa credit rating. Given the equivalent of an A/Baa credit, the maximum amount of Project credit available for the Alaska segment is estimated to be between $12 billion and $18 billion. For reasons described above, this amount will be affected by the funding strategy for the Canadian segment and for the expansion of the "lower 48" facilities. This total amount includes loans from domestic and foreign banks, foreign export credit agencies, and institutional lenders, all of whom are assumed to commit in early 1982. This assumes the satisfactory negotiation of acceptable terms with foreign export credit agencies, i.e. their willingness to accept the same credit support as the banks and longer than usual maturities, and the current reluctance of insurance companies to make forward commitments. We expect, however, that insurance companies might be willing to lend additional amounts beyond those contemplated in the funding study as the Project progresses.

We anticipate that the typical final maturity for the financing would be ten years with a grace period of five years and an average life of 7.5 years. There would, of course, be tranches with final maturities of 5-7 years from the smaller U.S. and European banks and of 12-15 years from certain larger banks and institutional lenders. The bulk of the bank financing would, however, have a ten year final maturity and a 7-8 year average life.

Without a dramatic improvement in credit quality, neither the availability of funds nor the average life of the financing would increase significantly. A reduction in credit quality below the equivalent of an A/Baa would, however, have a material adverse impact on both the amount and average life of the financing.

__Basic Financing Conditions__

The Banks have given considerable thought to the question of the basic financing conditions for the Project based on the assumptions you have provided:

1. Capital costs on an "as spent" basis of $21 billion for the pipeline and $6 billion for the conditioning plant, with a completion assurance pool of an additional $3 billion.

2. A debt equity ratio of 75%/25%, and an equity split of 70%/30% between Sponsors and Producers.

3. Your request that the Banks consider a completion pool of funds concept, i.e., irrevocable commitments from lenders and no formal undertakings from creditworthy parties to assure debt repayment in the event of non-completion by a date certain and/or pre-completion abandonment.

While we used these basic premises in our Phase I review and have drawn certain conclusions regarding their acceptability we suggest that any premises to be used in Phase II will need to be thoroughly tested as the Project's financial structure is developed.

Given the results of our funding study, and our review and consideration of the Project information forwarded to us, we have come to the following conclusions:

1. Our funding study clearly indicates that the overwhelming bulk of the financing will be available only if lenders perceive the credit structure to be the risk equivalent of debt of A/Baa quality.

   We believe that for the Project to be considered of this credit quality and, therefore, for commitments in the necessary amounts to be arranged prior to commencement of construction, the following basic criteria would have to be met:

   a) The ANGTS project must be economically and technically feasible.

   b) The debt must be supported by repayment assurances involving

      (i) during the pre-completion phase, a combination of

         -acceptable debt assumption arrangements by Sponsors, Producers and possibly other beneficiaries, and

         -acceptable commencement of billing provisions prior to the completion of the overall System;

      (ii) acceptable post-completion, cost of service transportation tariffs providing for debt service in all events;

      (iii) acceptable tracking provisions; and

      (iv) all tariff arrangements relating to debt service to have assurance of regulatory certainty mandated by law.

c) Sufficient funding must be considered by lenders to be available to meet potential overrun requirements.

d) The cash flow from the Project for debt repayment must be sufficient so that a substantial refinancing risk would not be present, particularly if the economics of the Project are potentially marginal in early years (see later discussion on refinancing risk).

It is our judgment that loans based on the completion pool of funds concept as presented will not be perceived by lenders generally to be of A/Baa quality. Consequently the bulk of the funds needed for the construction of the Project cannot be raised on that basis. Only a relatively small number of banks are capable of assessing and prepared to assume engineering-based risks as required under a completion pool of funds concept. We cannot ascertain the exact amount, if any, which might be raised for this Project on a completion pool of funds basis without having further developed the credit structure for all the financing. However, we strongly believe that: (i) the small number of banks prepared to provide financing on this basis would commit only a small part of their lending limits to such a credit and in the aggregate that amount would be a relatively small part of the total debt required, and (ii) such banks would require substantial inducements and difficult-to-achieve conditions precedent to any drawings under their commitments.

2. Although we have focused our analysis principally on the problem of funding availability and on basic conditions of the initial debt financing, several points relating to post-completion financing problems should be noted:

a) There could be substantial refinancing requirements in the early years of operation and perhaps in the later years of construction.

b) Once completed, the Project, assuming a properly functioning FERC-approved tariff, regulatory certainty, and demonstrated gas marketability, may command an investment grade rating for private placements and public issues.

c) On these assumptions, and with the understanding that not all refinancing requirements will have to be satisfied at one moment after completion, we believe that it should be possible to raise the amounts needed to refinance maturing loans.

3. We have not had an opportunity to review the bases on which the capital cost estimates are calculated, and therefore, are not in a position to comment on their appropriateness under modified debt financing concepts. Thus, we do not know the exact level of required funding for the Project and the overall ANGTS. To the extent that the debt requirements at the outset exceed the amount considered available for one credit, funds will have to be raised as entirely separate and discrete credits, under the full financial responsibility of creditworthy parties. Such commitments would be additional to any credit responsibility assumed by such parties in connection with debt repayment assurances for financings in the pre-completion phase of the Project.

Based on our conclusions and rather than pursuing the "completion pool of funds" concept as the primary method of raising debt financing (and it is our judgment that it cannot be relied upon) we suggest consideration of the following:

a) primary reliance on conventional project completion/debt assumption arrangements providing for an assured source of repayment by the equity owners in the event of non-completion and/or abandonment;

b) to the extent available, debt, which while not supported by debt assumption arrangements from equity owners in the event of non-completion, would be subject to conditions precedent to usage; these conditions would provide assurance that completion will occur and that the Project remains economically feasible;

c) debt support and/or debt from other beneficiaries of the Project; and

d) to the extent required, commencement of billing prior to completion of the overall system.

Given the capital cost estimates we have reviewed and based on the relevant financing parameters you have provided us, it is our considered opinion that all the debt support mechanisms outlined above in a), b), c), and d) will have to be aggressively pursued. We would strongly suggest that at this time the Sponsors place primary emphasis on the project completion/debt assumption arrangements.

In view of the Banks' conclusion that "the bulk of the funds needed for the construction of the project cannot be raised on a completion pool of funds basis" it may be desireable for the Sponsors to review the contingency provision in the capital cost estimates premised on the "completion assurance pool of funds" concept. This would yield a reduction of at least $3 billion in the $30 billion financing requirements as presented to us. Further reductions are, of course, dependent on the level of contingencies thought to be necessary including the rates of inflation and interest that are selected. We would encourage your review of the capital cost estimate to develop a base case for lender review of the total funding requirements under modified project financing concepts.

In summary, if the required credit support can be arranged, the Banks are of the opinion that a modified plan may well provide the basis for private sector financing of the Project. The nature of the modifications required are essentially, although not completely, covered in the suggestions we have recommended for your consideration. The way in which these suggestions are implemented will, of course, be instrumental, along with other conditions we have noted in this letter, in actually achieving the funding commitments that will be required.

We recognize that there are practical limits to the resources the Sponsors and Producers can and will commit to the Project, as well as limits to the extent of pre-completion consumer participation. We have not attempted to determine these limits, believing as we do, that these limits are best determined by negotiations within the partnership and by the regulatory and political process. The early determination of the relative interests of each equity participant will be a necessary precondition to the timely development of a financing plan.

While we have tried to provide you in this letter with our considered opinions on certain fundamental aspects important to the development of the financing, we feel that a forum for discussion of our views would be extremely helpful. We appreciate that the magnitude and complexity of the Project will necessitate a great deal of thought and discussion by all parties to arrive at a mutually agreeable financing plan. We would like to assure you of our enthusiastic support for and readiness to participate in such a discussion.

Sincerely,

BANK OF AMERICA NATIONAL TRUST
& SAVINGS ASSOCIATION

By
Vice President

THE CHASE MANHATTAN BANK
(NATIONAL ASSOCIATION)

By
Vice President

CITIBANK, N.A.

By Lorke C. Griswold
Vice President

MORGAN GUARANTY TRUST COMPANY
OF NEW YORK

By
Vice President

APPENDIX B

ANGTS PROJECT
FUNDING SUMMARY

The Funding Committee has been requested to assess the availability of funds from all significant sources for the Alaskan portion of the Alaska Natural Gas Transportation System (ANGTS). Given the size of the capital requirements and the complexity of the project the study has been divided into the geographic areas of the United States, Canada, Middle East, Europe, Asia, and Latin America. Assessing the overall appetite of the worldwide capital markets involved an in-depth study of the legal and policy limits of the banking community in each geographic area, the potential interest of non-bank institutional lenders, and the historical lending policies of the suppliers and export credit agencies in each country based on the potential equipment sources submitted by the Company.

In order to insure consistency in the findings of each of the studies and to maximize the amount of credit which could be raised from each market, it was necessary to establish certain common assumptions. In assessing the available credit within each country several major financial institutions were contacted. They were informed that their names would not be revealed in order to avoid a feeling of moral commitment and thus an overly conservative response. The fundamental assumptions utilized in conducting the survey were as follows:

(1) The borrower would be the risk equivalent of debt with a medium grade investment rating (A/Baa). If the project is not equivalent to this credit the amount of funds available to the project will drop significantly.

(2) The pricing would be fully commensurate with the risk involved.

(3) Within each country it is important to coordinate and segregate the individual financings with each category of financial institution in order to provide high visibility and thus motivation for strong participation. The coordination must not only extend to each individual financing for the Alaskan segment of ANGTS, but to the financing plans for the other segments of the pipeline system.

(4) Each financial institution must be approached correctly and at the appropriate level.

(5) It is important to give the financial institutions adequate time to analyze the material submitted in order to conduct their own assessments of the viability of the project. In this regard, presentations should be organized for the various countries.

(6) Specific presentations should be organized for the U.S. institutional market by the commercial bank advisory group due to their involvement in the project through an advisory role and as direct lenders. This would supply further credibility and maximize the funds available from this source.

Although the survey had been initially structured to segment the market in terms of the amounts available for 5 year commitments, 5-10 year commitments and 10-15 year commitments, the final conclusion reached was that 10 years (an in a few instances 12 years) would be the maximum overall term available except for the U.S. institutional market, but that within each individual financing one may need to offer a variety of commitment tenors and average lives in order to obtain the largest amounts. Therefore, the amounts listed for each goegraphic area take this into consideration. Two columns have been included for conservative and relatively aggressive estimates. These numbers are based on the optimal blend between local currency and U.S. dollars for each geographic area although the local currency content would relate principally to export facilities. The incremental sums from institutional lenders which could be raised in later construction phases have not been assessed in detail. To the extent that the sponsors are successful in maintaining the construction program on a timely basis within cost parameters it is certainly probable that additional funds from these sources would be available. Also to the extent that an investment grade rating were obtained, the incremental sums which could be obtained from the public markets in the U.S. and abroad could be substantial. The preliminary estimates for the amounts which could be raised under the above assumptions are as follows:

FUNDING ESTIMATE SUMMARY

IN THOUSANDS OF U.S. DOLLARS

U.S.		
Commercial banks	$3,000,000	$3,500,000
Institutional lenders	1,500,000	2,500,000
Canada		
Commercial banks	2,500,000	3,000,000
Europe		
Commercial banks	3,500,000	4,000,000
Middle East		
Commercial banks	500,000	500,000
Asia		
Commercial banks	1,800,000	2,400,000
Latin America		
Commercial banks	150,000	250,000
	$12,950,000	$16,150,000
Export Credit Facilities	1,700,000	1,700,000
	$14,650,000	$17,850,000

APPENDIX J

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

August 18, 1981

MEMORANDUM TO: Honorable Philip R. Sharp
Chairman
Subcommittee on Fossil & Synthetic Fuels
Committee on Energy and Commerce
House of Representatives

Honorable Clarence J. Brown
Ranking Minority Member
Subcommittee on Fossil & Synthetic Fuels
Committee on Energy and Commerce
House of Representatives

FROM : Charles A. Moore
General Counsel
Federal Energy Regulatory Commission

RE : Proposal by Sponsors of the Alaskan Natural Gas Transportation System (ANGTS) for Congressional Waiver of Sections 4, 5, 7 and 16 of the Natural Gas Act in Certain Respects Pursuant to Section 8g of the Alaskan Natural Gas Transportation Act of 1978

Questions Presented

By letter of July 24, 1981, to C. M. Butler III, Chairman, Federal Energy Regulatory Commission, 1/ you requested a legal memorandum addressing the following questions:

1/ Hereinafter, the term "Commission" refers to the Federal Power Commission at all times before October 1, 1977, and the Federal Energy Regulatory Commission at all times thereafter.

(a) The full implications of the proposed waiver quoted hereinbelow, (b) whether there have been past Commission actions which justify the desires of the sponsors to have Congress provide the waiver, (c) hypothetical situations which would work to the injury of the pipeline sponsors of ANGTS or other participants in the project should no such waiver be provided by Congress, (d) hypothetical situations which might work to the injury of resale customers and consumers should such a waiver be provided by Congress, and (e) the reasonable likelihood of the hypothetical situations actually occurring.

The text of the waiver request, as set forth in your letter, is as follows:

> Authority to Modify or Rescind Orders
>
> Waive Sections 4, 5, 7, and 16 of the Natural Gas Act to the extent that such sections would allow the 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 shippers of Alaska gas of (1) all costs related to the purchase of such gas at just and reasonable rates, and (2) transportation of such gas pursuant to an approved tariff.

We are advised that this text is currently a topic of discussion at staff levels in the Administration and the Congress, and that the text may be revised in one or more respects. Accordingly, the memorandum is expressly limited to the preceding text, although I will be pleased to respond as expeditiously as possible to any questions you might have in connection with material changes in such text.

Discussion

1. Background

As you know, the ANGTS is an international project created to transport natural gas from the North Slope of Alaska, through Canada, to the lower 48 states. The United States portion of the system consists of three segments: (1) the Alaska segment, running from Prudhoe Bay on the North Slope to the Yukon border; (2) the Western Leg, running from the British Columbia border to California; and (3) and the Northern Border pipeline, running from a point on the Canadian border near Monchy, Saskatchewan, to Dwight, Illinois.

The ANGTS is unlike any other gas pipeline in the United States in that it is governed by a unique legal framework. The Alaska Natural Gas Transportation Act (ANGTA), 15 U.S.C. section 719, et seq., enacted by Congress in 1976, supplements (but does not replace) the Natural Gas Act: certificates are issued under the Natural Gas Act pursuant to procedures mandated by ANGTA.

Pursuant to Section 7 of ANGTA, the President, in September of 1977, submitted his Decision and Report to Congress on the Alaska Natural Gas Transportation System (Executive Office of the President, Energy Policy and Planning) which designated both the project sponsors and the route for the ANGTS as well as many conditions for its construction. Congress approved the President's Decision by Joint Resolution, which became law on November 8, 1977. H.R.J. Res. 621, Pub. L. No. 95-158, 91 Stat. 1268, 95th Cong., 1st Sess. (1977).

The ANGTS is also governed by two international agreements with Canada, both of which have the force and effect of law. The "Agreement Between the Government of the United States of America and the Government of Canada Concerning Transit Pipelines," entered in force October 1, 1977 after ratification by the Senate, applies to all pipelines in both countries whenever one country's pipeline carries the other country's gas or oil. The treaty mandates nondiscriminatory treatment.

The "Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline," signed by representatives of the two governments on September 20, 1977, is an executive agreement that was made part of the President's Decision (pages 47-83). Inasmuch as the Decision was approved by Congress, it (including the Agreement) has the legal status of a statute. The Agreement specifies the route of the ANGTS, and contains numerous conditions. Pursuant to the Agreement, our Commission has consulted with the National Energy Board of Canada in coordinating respective certification of the various ANGTS segments in the U. S. and Canada, including related imports of Canadian gas to support the "prebuilding" of the lower half of the system.

One other relevant item of legislation is Reorganization Plan No. 1 of 1979, which was submitted by the President to the Congress and not disapproved by the Congress. The Plan establishes the Office of the Federal Inspector, which reports directly to the President. The Inspector is responsible for monitoring the construction of the pipeline, and for coordinating all federal permitting and certification of it. The Plan transfers to the Inspector the Commission's Natural Gas Act Sections 3 and 7 jurisdiction to enforce the Commission's certificates and import authorizations issued to the ANGTS project sponsors.

Two categories of tariffs are involved. The project sponsors will own and operate the various segments of the ANGTS, but will not buy or sell the gas transported through it. The shippers will buy the gas at the Prudhoe Bay Field, ship it through the sponsors' facilities, and sell it somewhere at the other end of the pipeline. The sponsors will have tariffs authorizing charges to the shippers. The shippers will in turn have tariff provisions authorizing charges to their customers for the sale of the gas, which charges will include in some form reimbursement of the shippers for the transportation charges paid by the shippers to the sponsors, as well as reimbursement for the costs of purchasing the Prudhoe Bay Field gas.

Thus, for example, if a shipper buys gas at Prudhoe Bay for sale in Detroit, the shipper would incur separate transportation charges billed by the respective sponsors of the Alaska segment, the Canadian segment, and the Northern Border segment of the system. That shipper would request a tariff authorizing "flow through" to its customers of the full amount of transportation charges paid to the sponsors of each of the three pipeline segments through which the gas was transported, as well as the full cost of the gas itself.

The "flow through" issue is often referred to as "tracking" of charges. Tracking of gas purchase costs is authorized by the Commission's regulations, through purchased gas adjustment clauses. (See 18 C.F.R. 154.38.) Tracking of transportation charges has been authorized in certain instances on a case by case basis.

In Order Nos. 31 and 31-B, 2/ the Commission approved in principle the tracking by ANGTS shippers of transportation charges billed by U. S. certificated ANGTS project sponsors (i.e., the sponsors of the Alaska, Northern Border and Western Leg segments), but reserved for later resolution the issue of tracking the charges of Foothills Pipe Lines (Yukon) Ltd. (Foothills), the sponsor of the Canadian segment. The unresolved tracking issues (including tracking of Foothills' charges that have been approved by the National Energy Board of Canada) are currently under study by the Commission's Alaskan Delegate, who is preparing a report to the Commission.

The sponsors' and shippers' initial tariffs are approved by the Commission pursuant to Section 7 of the Natural Gas Act upon issuance of the certificates. Alaskan Northwest's pro forma tariff was approved in Order Nos. 31 and 31-B. Section 7 provides a "public convenience and necessity" standard. While the Commission may establish initial rates that meet the more rigorous "just and reasonable" standard in Sections 4 and 5 of the Act, it is not required by law to do so. The Commission must only find that the initial rates are in the "public convenience and necessity" and may reserve for later determination what the "just and reasonable" rate should be.

2/ Order No. 31, "Order Setting Values for Incentive Rate of Return, Establishing Inflation Adjustment and Change in Scope Procedures, and Determining Applicable Tariff Provisions," issued June 8, 1979 in Docket No. RM78-12; Order No. 31-B on rehearing, issued September 6, 1979, in the same docket.

Section 7(e) of the Natural Gas Act gives the Commission authority to attach conditions to certificates. The courts have construed broadly the Commission's responsibility under the Natural Gas Act to condition certificates with respect to rate terms and other matters affecting the public convenience and necessity. See, e.g., Atlantic Refining Co. v. Public Service Commission of New York, 360 U.S. 378 (1959); FPC v. Hunt, 376 U.S. 515 (1964). But see Panhandle Eastern Pipe Line Co. v. F.E.R.C., 613 F.2d 1120 (D.C. Cir. 1979), cert. denied, 101 S. Ct. 247 (1980).

Section 4 of the Act requires that all rates and charges be "just and reasonable." After certification, all changes in the initially approved tariffs and rates must be filed with the Commission pursuant to Section 4. The Commission, pursuant to prescribed standards and procedures, may "suspend" such changes for up to five months pending a hearing. If the changes are suspended, the prior approved tariffs and rates remain in effect during the period of suspension. The changes may take effect after the suspension period but subject to refund (with interest) depending on the outcome of the hearing process on contested issues or other disposition by the Commission.

Section 5(a) of the Act authorizes the Commission to institute a proceeding on its own initiative, to consider the justness and reasonableness of a certificate holder's rates and tariffs, and to determine new rates or tariff provisions if the existing ones are determined to be "unjust, unreasonable, unduly discriminatory, or preferential." Such changes can only be prospective; in a Section 5 proceeding the Commission cannot suspend rates or order refunds.

Section 16 of the Natural Gas Act authorizes the Commission to modify or rescind its orders after they have been issued. This authority, under appropriate circumstances, may be utilized for a variety of purposes, ranging from correction of mistakes to modification of certificate terms and conditions in light of changed circumstances.

2. Nature of the Financing

The subject waiver is sought from Congress by the project sponsors of ANGTS in connection with the financing of the project. The financing mechanism selected by the sponsors has been referred to as "project financing." The propriety of project financing has been addressed by the Commission on a number of occasions, most recently in Ozark Gas Transmission System, FERC Opinion No. 125, Docket No. CP78-532 (July 28, 1981). In that opinion, the Commission described project financing generally as follows:

> Project financing differs from conventional financing mainly in connection with loan security. Security generally takes one of two forms in a conventional financing. First, the project sponsor, or borrower, has sufficient unencumbered assets that the lender feels secure in making a loan on the basis of the borrower's general credit. The loan agreement, in such cases, may require any of a number of different undertakings on the part of the borrower to maintain his creditworthiness. Secondly, if the borrower does not have unencumbered assets sufficient to secure the borrowing, the lender may require the pledge of specific assets to be funded by the borrowing as collateral for the loan. As Judge Litt pointed out in his initial decision on the Alaskan Natural Gas Transportation System, this is itself a kind of project financing. In this case the lender is secure in the knowledge that the borrower has put enough money into the project that the economic value of the project, less equity and liquidation costs, will yield sufficient funds for the lender to recover the principal value of the loan and accrued interest. A convenient example of this kind of financing is the mortgage of a building.
>
> A project financing, as it has come to be known in energy projects before the Commission, is a financing in which the general creditworthiness of the borrower is either insufficient or allegedly unavailable to secure the borrowing, and the underlying economic value of the assets to be financed are also insufficient to assure the lender that he will not lose his money. The latter inadequacy will presumptively obtain in the case of any pipeline financing, since the salvage value of the pipeline to be built should, in all cases,

> be less than the loan obligation. 21/ In this case, an optional financing vehicle is the stream of income to be generated by the project. However, that vehicle is only available in the event that the income stream can be assured whether or not the project should fail. Such assurance is sought in this case in the form of the so-called minimum bill. The minimum bill has been structured in a fashion which will yield sufficient revenues to cover debt service (both principal and interest payments), whether the project is successful or not. In the event the project were to fail, the minimum bill would be levied on the customers of the shippers in the form of a surcharge for gas they do not receive.
>
> ---
>
> 21/ In this regard Ozark's witness, Gary, states, 'Today we all recognize a mortgage on a pipeline is virtually worthless, except for one aspect, in making a legal investment.' Tr. 12/1064

Slip opinion, at 10-11 (footnotes omitted in part).

As the Commission pointed out in the Ozark case, substantial policy justification should be found in certificate applications before the Commission pursuant to which project financing is sought. In the case of the ANGTS, such justifications have already been considered by both the Executive and Legislative Branches of the Federal Government, as well as the Commission, and have been found sufficient to permit the project financing of the ANGTS. 3/

Some of the justifications have included the substantial amount of natural gas to be delivered by the project, the potential for displacement of large quantities of foreign oil, reduction of pressure on the U. S. balance of payments, net national benefits to both the U. S. and Canada, and the anticipated average cost of gas over the project life.

3/ See, generally, Federal Power Commission, Recommendation to the President, Alaska Natural Gas Transportation Systems (May 1, 1977).

3. Reason for the Proposed Waiver

The waiver has a rather singular purpose. It is intended to assure lenders for the project that the income stream which serves as security for their loans will not be reduced below the level necessary to retire the principal of the loan and to pay the interest thereon. It would accomplish this purpose by precluding the Commission from changing the rules of the game, so to speak, in a manner which would undercut the security for the loan. This objective would be achieved by withdrawing from the Commission its authority under the Natural Gas Act to change the project tariffs in such a manner as to reduce project revenues below the level necessary to service project debt. The request for the waiver evidences that certainty of the security is essential, *i.e.*, in this instance that the lenders will rely heavily and to their detriment on the orders of the Commission granting the certificate and establishing the tariffs as preconditions to the sponsors' take down of the construction loans.

All of the foregoing has been explicitly recognized by the Commission in FERC Order No. 31. 4/ In that order the Commission stated:

> The project sponsors have earnestly sought that this Order, especially as it relates to the tariff structure, provide assurance to prospective equity investors and lenders. The concern of the sponsors is wellfounded. The Commission fully recognizes that equity investors and lenders will make critical decisions respecting the financing of the construction of ANGTS in reliance on this Order.
>
> The Commission has articulated in great detail its rationale for this Order. Where reasoned alternatives were available, we have provided a thorough analysis of the issues and the basis for our conclusions. This thoroughness provides the investor's best security in relying on this Order.

4/ *Supra*, note 2, at 4 (mimeo).

The fact of the request for a waiver suggests that the project sponsors and the lenders feel that they need greater assurance than has been provided to date. The Chairman and I feel compelled to agree with that assessment. As the subsequent discussion and legal analysis shows, with the objective of "security" in mind, a waiver is clearly a far better assurance than an order of the Commission. For example, previous efforts by sponsors to secure additional certainty for lenders by attempting to obtain estoppel findings in Commission orders have been unsuccessful. 5/

5/ Applicants in the Great Plains case asked the Commission to make a very explicit estoppel case against itself by including certain statements in its order. Great Plains Gasification Associates, et al., FERC Opinion No. 69 (November 21, 1979) (reversed on other grounds, Office of Consumers' Counsel v. F.E.R.C., ___ F.2d ___ (D.C. Cir. 1980), Case No. 80-1303, decided December 8, 1980). The estoppel option will be discussed in the text, infra. In its initial brief to the Presiding Administrative Law Judge, Great Plains claimed the following:

> ". . . The lenders have indicated that they will require that the authorizations obtained [from the Commission] by the project companies contain [as a condition to take down of the loan for the project]:
>
> (1) A statement of the Commission's intention not to revoke or modify the tariff provisions approved by it for this project during the term of the bank loan;
>
> (2) A statement of the Commission's understanding that the lenders would not commit funds for this project without assurances that these provisions would continue in effect without modification during the term of the bank loan;
>
> (3) A statement of the Commission's intent to suspend the application as to this project of any future rule, order, or decision of general applicability which might affect the approved tariff provisions until after the conclusion of a full evidentiary hearing to determine the propriety and

(Footnote 5 continued on next page)

Important in the context of ANGTS financing is that a waiver would provide clear assurances and signals to foreign, as well as domestic, lenders. We are advised that a sizeable portion of the borrowing must be acquired from foreign investors because of legal lending limits and other institutional obstacles faced by domestic lenders.

4. Regulatory Risk

The regulatory risk perceived by lenders consists of two separate, but not unrelated, sets of events. They are: (1) that the Commission would change the tariffs initially approved on a claim of changed circumstances, and (2) that a subsequent Commission, composed of a majority with a different view of the public interest than the collective view of the Commission originally approving the tariffs, would change the tariffs to the detriment of the lenders in order to reflect their different views. The Commission's ability to change the tariffs in either of these events is not clear as a matter of law. It is not unlimited, but our analysis indicates that it is fairly broad. The effect of the proposed waiver would be to eliminate in material part the Commission's options -- to the extent they exist -- to change the tariffs in either of these cases.

5/ Footnote continued from prior page

lawfulness of such Commission action as it affects the tariff provisions on which the financing is based . . . ." Initial Brief of Great Plains Gasification Associates and the Customer Pipeline Companies, Docket Nos. CP78-391, et al., January 29, 1979, at 70-71.

Five other admissions were sought from the Commission, but those quoted are exemplary of what the lenders sought. Both the law judge and the Commission refused to provide them. See Opinion No. 69, at 63.

Similar estoppel findings were requested by the ANGTS sponsors in the proceeding that culminated in Order No. 31; however, they were refused in favor of the language quote at page 10, supra. As discussed hereafter, it is questionable whether such findings would achieve the desired or intended result.

5. Constitutional Question

Implicit in the questions articulated in your letter is the issue of whether the waiver is a reasonably necessary mechanism to provide the lenders with the certainty they seek. The threshold issue, in this respect, is whether there is any constitutional bar to the Commission taking the kind of action described in the subsequent paragraphs. If such a bar exists, the waiver would not be necessary. Our research indicates that this question has not been authoritatively answered by the courts. That is, there are no clear constitutional limits regarding the Commission's power to change tariffs, where parties have substantially changed position in reliance on such tariffs, and the Commission had prior, actual knowledge of such reliance. The Chairman and I believe that a respectable case could be made that it would violate basic constitutional principles of due process for the Commission to change tariffs not explicitly conditioned to permit change, when the Commission is fully aware that the tariffs form the basis of project financing, and the changes will in one way or another undercut that basis. However, there is an absence of authority to support such a proposition. 6/

6/ The question whether legislative or quasi-legislative action with retroactive effect works to deprive an owner of property without due process is somewhat analogous. Unfortunately, there are no clear principles, and the cases go both ways. See generally, text and cases collected in Cong. Research Service of Library of Congress, The Constitution of the United States of America: Analysis and Interpretation (1972), at 1165, et seq.

A case strongly suggestive that the principles of estoppel do not apply to federal agencies is Federal Crop Insurance Corp. v. Merrill, 332 U.S. 380 (1947). In that case, certain farmers were assured by a local agent of the federal corporation that a certain type of crop could be insured. In fact, rules of the corporation provided that such crops could not be insured, although neither the agent nor the farmers had actual knowledge of the regulations. Relying on the agent's advice, the crops were planted and subsequently destroyed.

(Footnote 6 continued on next page)

6/ Footnote continued from prior page

In holding that the farmers could not collect insurance for the crops despite the payment of premiums therefor and the inducement of the local agent's assurances, the Court indicated that knowledge of the rules contrary to the agent's advice would be imputed to the farmers because the rules were published in the Federal Register. Despite the difference of the facts in the Merrill case (farmers had relied on apparent rather than actual authority), the Court used strong language to suggest in dicta that the government corporation would be treated as an agency of the United States and would be immune from doctrines like estoppel. Id. at 384-85.

These dicta have led one commentator to take the following position:

> Merrill indicates that estoppel will not be used to protect an individual who has changed his position in reliance on administrative advice: 'It is settled law that no estoppel can arise against the government.' [Citing, Chapman v. Santa Fe Pac. R., 198 F.2d 498, 519 (D.C. Cir. 1951) (dissenting opinion), cert. denied, 343 U.S. 964 (1952).] B. Schwartz, Administrative Law (1976), at 133, et seq.

Professor Schwartz agrees with the Merrill-type result when the agency has acted in excess of its statutory authority. However, he goes on to say:

> . . . Both reason and policy argue that prejudicial reliance warrants invoking the doctrine of estoppel against the government in other cases: 'when the sovereign becomes an actor in a court of justice, its rights must be determined upon those fixed principles of justice which govern between man and man in like situations.' Id., at 135 (footnote omitted), citing Ritter v. United States, 28 F.2d 265, 267 (3d Cir. 1928).

(Footnote 6 continued on next page)

6/ Footnote continued from prior page

The following cases support Professor Schwartz's policy proposal: Brandt v. Hickel, 427 F.2d 53, 56-57 (9th Cir. 1970); Chapman v. El Paso Natural Gas Co., 204 F.2d 46, 53-54 (D.C. Cir. 1953); United States v. Lazy FC Ranch, 481 F.2d 985, 988-989 (9th Cir. 1973); Oil Shale Corp. v. Morton, 370 F. Supp. 108, 124-127 (D. Colo. 1973).

The decision in the Lazy FC Ranch case, supra, indicates that a line of federal estoppel cases may be emerging, and that such is required by elementary notions of fairness. 481 F.2d at 989. The Chairman advises that his view is consistent with that of Professor Schwartz and the Court in Lazy FC Ranch. However, absent an authoritative pronouncement on the matter by the United States Supreme Court, or specific federal legislation, I cannot render an opinion as General Counsel of the Commission that the Commission would in all or substantially all cases be estopped by its orders from changing the ANGTS tariffs in such manner as to impair the underlying security for the financing of the ANGTS. In my judgment, the best opinion that could be rendered would simply agree that the Commission is constitutionally prohibited from setting a confiscatory rate of return. As stated by the Supreme Court in Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 690 (1923):

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.

See also, F.P.C. v. Hope Natural Gas Co., 320 U.S. 591, 603 (1943). As the subsequent discussion reveals, short

(Footnote 6 continued on next page)

6. Statutory Question

The foregoing is not to suggest that there are no Supreme Court cases dealing with regulatory estoppel. To the contrary, there are two cases of considerable relevance; however, both are based on interpretations of the enabling legislation of other agencies. In the first of these, United States v. Seatrain Lines, 329 U.S. 424 (1946), the Court held that the Interstate Commerce Commission lacked the authority to alter the certificate of a water carrier on its own motion. The holding was based on the express statutory language which permitted such action with respect to motor carriers, and the absence of correlative statutory authority in the case of water carriers, in the Interstate Commerce Act.

5/ Footnote continued from prior page

of this constitutional limitation, the Commission has considerable latitude in the exercise of its jurisdiction under Sections 4, 5, 7 and 16 of the Natural Gas Act.

The fact that the lenders have induced the project sponsors to ask for the waiver may well indicate that an unqualified legal opinion cannot be obtained from lenders' counsel to the effect that a constitutional bar exists to provide an estoppel defense. A similar conclusion may be deduced from the request for estoppel admissions in the Great Plains case, supra, note 5.

In Civil Aeronautics Board v. Delta Air Lines, Inc., 367 U.S. 316 (1961), the Supreme Court considered a similar question. The Court determined that Section 401(g) of the Federal Aviation Act prohibited the CAB from altering a certificate of public convenience and necessity, even where the certificating order purported to reserve jurisdiction prior to certification to make summary modifications pursuant to petitions for reconsideration. Reaching this result, the Court's analysis was founded on the plain meaning of the language in the enabling statute and its legislative history.

The Delta case is of particular importance to the subject of this memorandum for two reasons. First, the Court clearly explained the nature of the problem with the following statement:

> Whenever a question concerning administrative, or judicial, reconsideration arises, two opposing policies immediately demand recognition: the desirability of finality, on the one hand, and the public interest in reaching what, ultimately, appears to be the right result on the other [footnote omitted]. Since these policies are in tension, it is necessary to reach a compromise in each case . . . . Id. at 321.

The second key element of the Delta case is the recognition by the Court that the limitations placed on the CAB under the Federal Aviation Act resulted from Congressional concern during the passage of its predecessor, the Civil Aeronautics Act of 1938, over the reliance on, and consequent expenditure by airlines of large sums of money on the basis of the CAB's certificate (route) decisions. In this connection, the Court stated:

> In short, our conclusion is that Congress wanted certificated carriers to enjoy 'security of route' so that they might invest the considerable sums required to support their operations; and, to this end, Congress provided certain minimum protections before a certificated operation could be cancelled. We do not think it too much to ask that the Board furnish these minimum protections as a matter of course, whether or not the Board in a given case might think them meaningless. It

might be added that some authorities have felt strongly enough about the practical significance of these protections to suggest that their presence may be required by the Fifth Amendment. See Seatrain Lines v. United States, 64 F. Supp. 156, 161; Handlon v. Town of Belleville, 4 N.J. 99, 71 A. 2d 624; see also 63 Harv. L. Rev. 1437, 1439, Id., at 331-332.

7. The Natural Gas Act

The Seatrain and Delta cases teach that the starting point in determining the practical necessity of the waiver as a security device is the language of the relevant enabling statute, the Natural Gas Act. Sections 4 and 7 are relevant, but the key provisions are Sections 5(a) and 16. Section 16 reads in pertinent part:

> The Commission shall have power to ... prescribe, issue, make, amend, and rescind such orders, rules or regulations as it may find necessary or appropriate to carry out the provisions of this act.

Section 5(a) provides, in pertinent part, that if the Commission:

> ... [S]hall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural gas company in connection with any transportation or sale of natural gas, subject to the jurisdiction of the Commission, or that any rule, regulation, practice or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate, charge, or classification rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. [emphasis supplied]

These statutory pronouncements are mandatory as opposed to precatory. The broad language of Section 16, when employed in conjunction with Section 5, has permitted the Commission to alter and amend conditions to certificated service with full approval by the courts. Section 5(a) has been interpreted as giving the Commission authority to alter the terms and conditions of certificated service even though the affected parties, acting alone, could not have changed them. F.P.C. v. Louisiana Power and Light Co., 406 U.S. 621, 646-647 (1972). In Opinion No. 754-A, Docket No. RP71-119, issued August 17, 1976, aff'd on other grounds, Hercules, Inc. v. F.P.C., 559 F.2d 1208 (3rd Cir. 1977), the F.P.C. concluded, with court approval, that it could exercise its Section 5 authority to promulgate new terms and conditions attached to certificates authorizing initial service.

The combined effect of Sections 5(a) and 16 is to require the Commission to amend terms and conditions of a certificate if those terms and conditions prescribe tariff provisions subsequently found to result in rates or charges which are not just and reasonable. As the United States Court of Appeals for the District of Columbia Circuit stated in American Smelting and Refining Company v. F.P.C., 494 F.2d 925, 940-941 (1974), cert. denied sub nom., Southern California Gas Co., et al., v. F.P.C., 419 U.S. 882 (1974), once the Commission finds that an existing rate or charge is unjust or discriminatory, 7/ it "must prescribe the remedy for that condition." 8/ If the existing illegal rate or charge is the result of the operation of a certificate condition, the remedy clearly will lie in the revocation or alteration of the order prescribing that condition, and thus the certificate itself.

7/ The Commission's authority to find that a tariff (previously determined to be just and reasonable) no longer functions in a reasonable manner has been upheld by the U.S. Court of Appeals for the District of Columbia Circuit in Pacific Gas Transmission Co. v. F.P.C., 536 F.2d 393 (1976).

8/ The D.C. Circuit has also taken this position in Pacific Gas Transmission Co. v. F.P.C., supra., where it stated at page 396 that "[a]fter such a finding, the Commission had not only the power but a solemn duty to take immediate action."

Furthermore, the unique nature of the Alaskan Northwest tariff provisions may subject them to amendment on another basis. Because they were developed in a rulemaking, the provisions of Order No. 31 arguably are not the result of the Commission acting in a judicial capacity, but in a legislative one, formulating and applying policy. The distinction is important because where the Commission acts in the former capacity, applying law or policy to past facts, a decision on the merits as to a disputed, and litigated issue of fact becomes final. United States v. Utah Construction and Mining Co., 384 U.S. 354, 421-422 (1966); Davis, Administrative Law Treatise, §18.09 (1970 Supp.). In the latter case, the Commission is free to take appropriate steps without being bound by its prior actions. Permian Basin Area Rates Cases, 390 U.S. 747, 789 (1968); Public Service Commission, State of New York v. F.P.C., 511 F.2d 338, 353 (D.C. Cir. 1975). The policy determination in this case has been that the public convenience and necessity required the assurances to investors in the ANGTS provided for by the tariff provisions of Order No. 31. Arguably, the Commission has determined that as a matter of policy, at least under present circumstances, a tariff designed to meet the conditions of Order No. 31 will be just and reasonable. The same reasoning might also apply to the shipper tracking provisions in the event that such provisions are adopted by the Commission through rulemaking procedures. Although it is questionable whether the rulemaking-adjudication distinction would be given great weight in the context of the facts at hand, it might be enough to convince a future Commission that it could, within the law, conclude that a different policy determination better serves the public interest.

From the foregoing it is clear that there is a plausible case for Commission authority to subsequently alter the tariff conditions of Alaskan Northwest's certificate, relying on Sections 16 and 5(a) of the Natural Gas Act and judicial pronouncements authorizing agencies to make changes in policy. The foundation for that case is the general principle that a policy determination made by a present Commission cannot preclude a future Commission from making a policy determination to the contrary, provided that in doing so it adequately explains the reasons for its new position, Consolidated Gas Supply Corp. v. F.P.C., 520 F.2d 1176 (D.C. Cir. 1975), whether or not there has been a change of circumstances. Greater Boston Television Corp. v. F.P.C., 444 F.2d 852 (D.C. Cir. 1970). A corollary to that principle is that a present Commission cannot bind a future Commission so as to preclude the prospective operation of Section 5. Optional Procedure for Certificating New Producer Sales of Natural Gas, 48 F.P.C. 218, 223 (1972); Pacific Gas Transmission Co. v. F.P.C., supra. These rules are analogous to those applicable to the legislature: namely, this Congress cannot preclude legislation, or amendments to legislation, by the next Congress.

8. Reasonableness of the Waiver Request

This line of analysis suggests several important conclusions, which bear ultimately on the recommendation of this memorandum. First, the presence or absence of a constitutional ban to the impairment by this or a future Commission of the tariffs upon which the lenders will rely is unclear. Second, there appears to be no statutory bar, such as was found to exist in the Seatrain and Delta cases, which would preclude the Commission from changing the tariffs. Even though it is clear that commentators, the Courts, at least by way of dictum, and the past and probably current Commissions accept the principle that elementary notions of justice should allow the project lenders to rely in good faith on the decisions of the Commission in making their loans, the request of the project sponsors indicating their "desires . . . to have these provisions waived" appears to be based on a concern as to the certainty of the federal-estoppel doctrine under the Natural Gas Act. The questions that remain are those that are directly raised by your letter. They ask in essence whether there are either historical or predictable future facts which support or impugn the legislative request. That is, assuming that the waiver request is not patently unreasonable, is there a historical legal perspective from which the Congress could judge the future and find sound public reasons to grant or deny the waiver.

9. <u>Past Commission Actions</u>

For the moment I will defer to subsequent paragraphs the question of "the full implications of the waiver" and turn to your second specific question: whether there have been past Commission actions which justify the desires of the sponsors to have the subject sections of the Natural Gas Act waived. In this connection, the following contains a summary of recent cases, representative of past Commission actions, which involved issues of claimed detrimental reliance. Having done so I will leave it to the Subcommittee to conclude from these decisions whether or not the project sponsors' request is justified.

A. Jurisdiction: <u>Distrigas Corporation, et al. v. F.P.C., et al.</u>, 495 F.2d 1057 (D.C. Cir. 1974), <u>cert. denied</u>, 419 U.S. 834 (1974).

This proceeding involved, in pertinent part, a filing by Distrigas Corporation and its affiliates, Distrigas of New York Corporation and Distrigas of Massachusetts, (Distrigas) which requested the Federal Power Commission to grant Distrigas the authority under Section 3 of the Natural Gas Act to import liquefied natural gas (LNG) from Algeria. 9/ The filing also contained a request by Distrigas for the FPC to issue a disclaimer of the Commission's jurisdiction under Section 7 of the Natural Gas Act. 10/

9/ Following regasification, more than 80 percent of the gas was to be sold in the state of importation to distributors and direct customers and the remainder to distributors in neighboring states.

10/ The imported LNG was to be delivered and regasified at facilities at Staten Island, New York and Everett, Massachusetts.

The Commission in a three to two vote granted the requested Section 3 authorization without condition but, noting that this was a novel situation, reserved the right to add conditions in the future if circumstances should change. The Commission noted that Section 3 of the Natural Gas Act specifically provided for such future amendments. However, the Commission did not find Section 7 jurisdiction over the regasification facilities and service nor over the facilities and services involved in the sale of the regasified LNG in the state of importation. 11/ The result of the decision was that there was no jurisdiction under Section 7 or Section 3 (by way of conditions to the import authorization) over the regasification facilities and service nor over the intrastate facilities and service. The Commission indicated its hope that this disclaimer of jurisdiction would make the project more attractive to private investors and "lead to more gas at a lower price to the consumer than if [the Commission] controlled every detail and decision related thereto." Two Commissioners dissented, arguing that the Commission should take jurisdiction under Sections 3 and 7 of the Natural Gas Act over the regasification facilities and the "intrastate" facilities.

Following the Commission's decision, Distrigas "assertedly in reliance on the Commission's limited jurisdictional disclaimer, . . . proceeded to construction of its Everett and Staten Island facilities, expending very substantial sums on each." In a new filing, Distrigas also applied for Section 3 authorization to import significant additional quantities of natural gas and for Section 7 authorization to sell these additional volumes, as well as certain of the originally authorized volumes, in interstate commerce.

11/ The Commission did take jurisdiction under Section 7 of the Natural Gas Act over the sales of gas which was ultimately destined for resale in interstate commerce. However, it found that jurisdiction over such sales attached only at the tailgate of the regasification plant.

Meanwhile, at the Commission two of the original three person majority had left and had not been replaced. Therefore, the two dissenting Commissioners were now a majority. In response to Distrigas' applications, they found that circumstances had changed since Distrigas' original application had been acted upon by the Commission. Specifically, they stated that the original Distrigas application proposed new and increased sales for resale in interstate commerce. Therefore, the Commission held that Section 7 certification was mandated for all of Distrigas' facilities.

On appeal, Distrigas argued, among other things, that once the Commission's previous decision on the jurisdictional issue was final and Distrigas had subsequently acted in reliance on that decision by (1) contracting with its customers and (2) constructing its facilities, the Commission was foreclosed from changing its mind and asserting jurisdiction where it had previously declined to do so. Distrigas cited the Seatrain case, 12/ where the Supreme Court had overturned the Interstate Commerce Commission's attempt to revoke a certificate previously granted to a water carrier.

The Court found that the Commission had the authority to issue the order it had issued under Section 3 of the Natural Gas Act but remanded for additional proceedings before imposition of any requirements to certification under Section 7. The Court distinguished Seatrain on the basis of lack of statutory authority in that case, and noted that both Section 3 of the Natural Gas Act as well as the Commission's previous order specifically contemplated changes and amendments. The Court further found that if Distrigas had relied on an interpretation of the original Commission order to the contrary (i.e., that the original Commission order granted Distrigas a permanent immunity from regulation), Distrigas' reliance was misplaced.

12/ Supra, at 15.

As part of its basis for rejecting the estoppel argument, the Court concluded that Distrigas' claim of injury was at that point hypothetical in nature since Distrigas had not demonstrated that the Commission would not ultimately authorize Distrigas' proposal.

On remand, the Commission granted Distrigas' application subject to certain conditions.

The Distrigas case is one where the Court approved a changed Commission's reversal of a previous Commission's ruling upon which the company and its lenders had arguably relied to their detriment. As a basis for that approval the Court stated, "any 'right' to non-regulation that the Commission's previous decision can be supposed to have vested in Distrigas was entirely contingent on the Commission's continuing to view such non-regulation as in the public interest." However, two facts tend to distinguish Distrigas from the ANGTS. One is the conditions cited by the Court in the original Section 3 authorization, which arguably placed Distrigas and its lenders on notice that the rule could change. The other distinguishing fact was that the Court found that the Commission's decision had not yet injured Distrigas and that it might not in the future. Presumptively, the matter was resolved at the Commission level in a way which did not adversely affect Distrigas or its lenders. Nonetheless, one could conclude that the uncertainty caused by the Commission's reversal is the type of action the ANGTS lenders seek to protect themselves against.

B. Cost of Service Tariff: Pacific Gas Transmission Co. v. F.P.C., et al., 536 F.2d 393 (D.C. Cir. 1976), cert. denied, 429 U.S. 999 (1976).

This case involved a Commission order which, pursuant to Section 5(a) of the Natural Gas Act, changed in part Pacific Gas Transmission Company's (PGT) cost-of-service tariff after a full hearing. Prior to the Commission decision, PGT had been permitted to adjust its rates automatically on a monthly basis to reflect all changes in its costs, including amounts for gas purchased from Canadian producers for resale in the United States. This tariff had been in effect since PGT was first authorized to import gas from Canada in 1960. 13/

In 1974 and 1975, after a hearing under Section 5(a) of the Natural Gas Act, the Commission modified PGT's cost-of-service tariff to provide that changes in the cost of gas purchased by PGT from Canadian suppliers could be passed on to PGT's customers only after PGT had applied for the rate increase pursuant to Section 4 of the Natural Gas Act, and after any suspension period imposed by the Commission thereunder. The Commission revised the tariff to provide that such filings would be subject to suspension by the Commission pursuant to Section 4 of the Natural Gas Act and, if suspended, subject to refund and possible reduction as provided in Section 4 of the Natural Gas Act. The Commission justified the revised tariff by stating that Canadian authorities had recently begun to require that significantly increased prices be charged for Canadian gas sold for resale in the United States. Furthermore, Canadian authorities had changed their pricing policy by referencing it to prices for alternate energy sources (primarily oil products) in markets served by Canadian gas. This formula change signaled further significant increases in the cost of gas purchased by PGT from Canadian producers (as much as four times higher than prior to the Section 5 proceeding). The Commission found that these changed circumstances rendered PGT's existing tariff "unjust and unreasonable" and required prior Commission review of rate increases for Canadian gas before they could be passed on to consumers in the United States.

13/ See Pacific Gas Transmission Company, 24 FPC 134 (1960).

On appeal, PGT argued in part that the Commission-ordered modification of its tariff could result in delay or outright denial of its recovery of increased Canadian purchased gas costs which, in turn, would financially destroy PGT. PGT also argued that the Commission was without power to modify the cost-of-service tariff which a previous Commission had approved in 1960 when PGT was originally authorized to commence the importation of Canadian natural gas.

The Court denied all of PGT's claims and affirmed the Commission order and its action revising the tariff under Section 5(a). In support of its holding, the majority noted that the Commission had granted prompt authorization under Section 4 for Canadian gas rate increases which took effect after the disputed tariff change. The majority opinion indicated that failure of the Commission to include such increases might well be to "abdicate" its responsibilities under Section 4. However, Judge Bazelon in a dissenting opinion directed considerable criticism towards the Commission for injecting uncertainty into PGT's financial position. As the dissent stated: ". . . the FPC concedes that had PGT been required to absorb even the initial 32 cent price increase for a short period of time it would have been driven out of business, and 2,000,000 consumers would have been deprived of 40% of their gas supply." (536 F.2d at 397.)

C. Advance Payments (30 day rule): <u>Tennessee Gas Pipeline Co.</u>, <u>et al</u>. v. <u>F.E.R.C.</u>, <u>et al</u>., 606 F.2d 1094 (D.C. Cir. 1979), <u>cert. denied</u>, 447 U.S. 922 (1980); <u>Natural Gas Pipeline Co.</u> v. <u>F.E.R.C.</u>, 590 F.2d 664 (7th Cir. 1979); <u>United Gas Pipe Line Co.</u> v. <u>F.E.R.C.</u>, 597 F.2d 581 (5th Cir. 1979); <u>Trunkline Gas Co.</u> v. <u>F.E.R.C.</u>, 608 F.2d 582 (5th Cir. 1979).

These cases involve interstate natural gas pipelines which, pursuant to a series of Commission rulemakings, including most notably Order Nos. 465 and 499, made interest-free loans (advance payments) to natural gas mission, pursuant to the reasonable and appropriate standard, to establish in individual pipeline rate cases decided after the rulemaking orders had issued and after the advance payments contracts had been executed, that rate base treatment of advance payments would not be allowed more than thirty days in advance of when they were spent by the producers.

The three separate circuit courts reversed the Commission orders decided on this basis. However, the D.C. Circuit in Tennessee rejected the pipelines' claims of retroactive ratemaking and detrimental reliance and directed the Commission on remand to develop a timing relationship supported by substantial evidence. The Fifth Circuit in the United and Trunkline cases and the Seventh Circuit in the Natural case found that it was impermissible retroactive ratemaking to impose a timing requirement on Order No. 465 advances and that the pipelines had relied to their detriment on the absence of a timing requirement in the Order when they made advances to producers. Therefore, they reversed the Commission decision on the Order No. 465 advances and directed inclusion of the designated amounts in the respective pipelines' rate bases. Since Order No. 499 contained at least an ambiguously general reference to a timing relationship, those portions of the Commission decision were remanded because of a lack of substantial evidence supporting that portion of the Commission orders. Although the Commission was reversed in these cases, language from the Court's opinion in Tennessee is illustrative of the "regulatory risk" inherent to an industry subject to the Commission's jurisdiction.

> We find that petitioners' arguments in support of their interpretation (of estoppel facts) are undercut by consideration of the character of the advance payment program as an experimental departure from well accepted and understood regulatory law. (606 F.2d at 1108.)

* * *

> One of the risks incurred by the pipelines has been the 'regulatory risk' that an experimental program such as advance payments might miscarry, and that administrative readjustment would not prevent substantial adverse impact. (606 F.2d at 1120.)

D. Dedication of Gas Reserves: Air Products & Chemicals, Inc. v. F.E.R.C., ___ F.2d ___ (5th Cir. 1981), Case No. 78-2011, decided July 16, 1981.

This case involves a Commission order which ended a prior Commission policy under the "Chandeleur incentive doctrine" (of approximately seven years duration) which allowed offshore natural gas producers to reserve for their own use a portion of gas reserves which otherwise would have been dedicated to the interstate market. The prior policy had allowed these reservations as an incentive to producers to expedite the exploration and development of offshore reserves of natural gas. The Commission, in its final order, found that the reservation incentive was no longer needed because, among other things, the interstate market was suffering severe curtailments and thus the gas which would be reserved by the producers was needed to serve the interstate market.

On appeal the producers argued, among other things, that they relied to their detriment on the prior FPC policy allowing reservations and that it was unfair and illegal for the Commission to reverse its policy in an adjudicated case instead of a rulemaking proceeding to be applied prospectively.

The Court remanded the case to the Commission because of the improper way in which the Commission relied on extra-record evidence to support its decision, but it rejected the producers' arguments of detrimental reliance on the prior Commission policy. The Court noted that the old Commission policy was continually attacked by consumer groups in various cases and that it was, at its inception, described by the FPC as experimental. In sum, the Court found that the policy was never "well established" enough to have caused detrimental reliance thereon by producers or anyone else. The Court noted further that the producers were not precluded from selling the gas in interstate commerce for a fair price but rather were prohibited from reserving the gas for their own use.

E. Unsuccessful Project Costs: Tennessee, et al. v. F.E.R.C., 606 F.2d 1094 (D.C. Cir. 1979), cert. denied, 447 U.S. 922 (1980).

This proceeding involved, among other things, an attempt by Transcontinental Gas Pipe Line Corporation (Transco) to recover costs associated with four unsuccessful projects related to the production of synthetic natural gas (SNG). The Commission denied recovery of these costs because they were not "used and useful" in providing service and could not be charged to ratepayers. 14/

On appeal, Transco argued that it had spent $22 million on these ultimately unsuccessful projects in purported reliance on a Commission policy allowing recovery of the costs of the projects if they proved to be unsuccessful. The Court found that the Commission had no policy allowing recovery of these costs and then affirmed the Commission's decision.

14/ A possible concern of the lenders is that a dogmatic application of the "used and useful" maxim would result in similar treatment of the ANGTS if the project were to suspend operation after completion or, through no fault of the sponsors they were unable to commence operation after completion. The need for assurances to the contrary (the minimum bill) provides a major impetus for project financing as opposed to conventional financing.

Other cases in which the Commission is currently under criticism for assertedly changing policies to the detriment of jurisdictional companies include (i) applications for rehearing of Commission Opinion No. 90 15/ and Order No. 94, 16/ and (ii) the oil pipeline cases where revision of the ratemaking methodology formerly employed by the Interstate Commerce Commission is under consideration. 17/

However, these cases should not be taken as a suggestion that the Commission never accords finality to its orders. In Texaco, et al., Docket No. CI77-329, et al., 13 FERC ¶ 61,222 (1980), for instance, a United States Senator filed a pleading on July 21, 1980, seeking to reopen a case settled on February 10, 1978. Part of the Senator's argument was that changed circumstances justified reopening the case, but the Commission refused to grant the intervention and declined to disturb its earlier order.

Arguably, cases such as those described above represent a possible "justification" or reason why the sponsors have now sought the waiver from Congress. At the same time, however, these decisions and others of a similar nature have generated some sympathy in the courts and have begun to establish the proposition that estoppel is available as a defense against the government if the government's wrongful conduct threatens to work a serious injustice and if the public's interest would not be unduly damaged by the imposition of estoppel. Lazy FC Ranch, supra, 481 F.2d at 989. Nevertheless, because the estoppel doctrine has not been fully developed under the Natural Gas Act, it is fair to state that only a waiver would provide the lenders with the same sense of legal certainty that a firmly established "regulatory estoppel doctrine" would afford these investors. Whether this legal uncertainty "justifies" the requested waiver is a value judgment best left to Congress. With this in mind, it is appropriate to consider your questions as to hypothetical situations creating injury to project participants.

15/ 12 FERC ¶ 61,080 (1980).

16/ 12 FERC ¶ 61,080 (1980); FERC Statutes and Regulations, ¶ 30,178 (1980).

17/ Trans Alaska Pipeline System (TAPS) (Phase I), Docket Nos. OR78-1, et al.; Williams Pipe Line Company (Phase I), Docket Nos. OR79-1, et al.

10. Hypothetical Injuries to Project Participants

Our analysis has produced four general sets of hypothetical circumstances which might induce a Commission response changing the tariff provisions related to the project, absent the waiver. They are:

(1) a changed economic environment resulting in materially different costs of capital (i.e., interest rates and return on equity) from those extant at the time of initial approval;

(2) changed amounts of natural gas available to be transported resulting in a materially different economic life for the transportation system;

(3) changed economics of the gas to be delivered by the system, relative to other sources of energy supplies, warranting an altered revenue pattern in order to avoid more serious economic dislocations; and

(4) premature project failure.

As a consequence of these general events, the following hypothetical Commission actions might take place:

(a) Upon a finding of changed circumstances the Commission could determine, pursuant to Sections 5, 7 and 16 of the Natural Gas Act, that the cost-of-service tariff (which provides that Alaskan Northwest's rates will be adjusted twice a year by a formula that requires Alaskan Northwest to change its rates to reflect actual costs in its charges to shippers) was no longer appropriate. The Commission could then require Alaskan Northwest to charge a stated rate, such as a flat rate per MMBtu of natural gas transported, and require filing pursuant to Section 4 of the Natural Gas Act to be made prior to the effectuation of any increase in that stated rate. The rate increase filing could be suspended for up to five months, and the proposed rates thereafter collected could be subject to possible reduction and refund with interest.

The risks to Alaskan Northwest in the event of a Commission-ordered change to a stated rate form of tariff involve the adverse economic impacts resulting from the regulatory lag attendant to putting into effect a proposed rate increase under Section 4 of the Natural Gas Act. The regulatory lag consists of the sum of: (1) the time necessary to prepare a Section 4 rate filing plus (2) the one-month notice requirements between the time the filing is made and the earliest possible effective date (absent a waiver of the notice requirements) plus (3) a suspension period of up to 5 months beyond the proposed effective date. During the lag period, Alaskan Northwest sponsors would not be able to recover all of the costs previously covered by operation of the cost-of-service tariff.

As noted previously, the FPC modified in part the cost-of-service tariff of Pacific Gas Transmission Company to require Section 4 filings to recover increased Canadian purchased gas costs. However, the Court concluded that the result was justified inasmuch as the Commission had, pursuant to Section 4, allowed a "non-niggardly" flow-through by the company of increased gas costs, notwithstanding the dissent's concern that delay would have resulted in adverse consequences.

(b) Alternatively, the Commission could decide at a future time to leave the cost-of-service tariff intact but remove the minimum bill (which guarantees recovery of actual operation and maintenance expenses, actual current taxes and debt costs). 18/ The consequence of this action could

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18/ The minimum bill provides for the recovery of actual operation and maintenance expenses, actual current taxes, and all amounts necessary to service debt including interest and scheduled retirement of debt. Under no circumstances would debt service be impaired.

Recovery of equity investment and return on equity investment is, however, treated differently. The "90 percent billing adjustment ratchet" reduces charges to eliminate return on equity investment and associated taxes for any service diminution below 90 percent of tendered gas. This tariff provision would be applicable in instances when the reduction in service for any one month was greater than 10 percent. The reduction in charges to reduce the return on equity and

(Footnote 18 continued on next page)

be that during periods of interruption exceeding thirty days Alaskan Northwest would bear all of the financial consequences of the interruption because it would not be able to charge the shippers for any costs incurred during the period of interruption. 19/

(c) Another hypothetical involves a situation wherein the ANGTS project fails some time after the date construction had commenced. Assume further that upon review of

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18/ Footnote continued from prior page

associated taxes would be proportional to the percentage of volumes tendered but not transported. The pipeline would be permitted to recoup any such billing adjustments by transporting volumes in excess of the contract level in subsequent months. The charge for such "Billing Adjustment Gas" transportation would be computed by using the same billing adjustment (i.e., the same dollar per Dekatherm). Any service reduction below 100% but more than 90% would be accounted for as "No Billing Adjustment Gas." As such, this gas would be transported in subsequent months at no added charge to the shipper.

The "90 percent billing adjustment ratchet" also operates during periods of interruption of service. It ceases to be operative, however, for any period of total cessation of service for more than 30 days. Beginning with the thirty-first day of any total cessation of service, the portion of the charges attributable to "equity costs" would be collected subject to refund pending a showing by Alaskan Northwest that it should be permitted to retain equity costs collected during the period of cessation of service. Equity costs, in this context, are defined to be "that portion of depreciation expense not necessary for debt service and associated taxes." (Order No. 31, at 181-182.)

The above discussed ANGTS tariff provisions differ substantially from lower-48 pipeline tariff provisions in a number of important respects. It is fair to state that the ANGTS tariff contains unique, "first-of-a-kind", provisions which have not been previously granted by the Commission.

19/ This assumes that in eliminating the minimum bill the Commission would also eliminate the opportunity to collect equity costs subject to refund and to make a showing pursuant to the provisions described in note 18, the circumstances surrounding the project failure, a future Commission decided, pursuant to Sections 5, 7 and 16 of the Natural Gas Act, to reverse a previous decision in principle to require consumers to pay all debt costs regardless of the circumstances once final certification had been granted and debt servicing obligations had commenced. Thus, the partners of Alaskan Northwest (including sponsor-shippers) would be required to absorb all Alaskan Northwest debt costs as well as other (such as equity) Alaskan Northwest costs. Such a Commission decision would have an immediate severe financial impact on Alaskan Northwest, with the degree of severity being a function of the financial health of its partners.

(d) The Commission could decide several years in the future, pursuant to Section 5 of the Natural Gas Act, to direct the shippers of the gas to remove from their respective tariffs the rate adjustment (tracking) provisions which permit the shippers to flow through increases in transportation costs without the necessity of making a full filing under Section 4 of the Natural Gas Act (reflecting <u>all</u> current costs and revenues, not merely the <u>increased costs</u> of transportation). 20/ In these

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20/ While the Commission has decided in principle to allow the shippers to track in a timely manner amounts reflecting transportation costs paid to the ANGTS sponsors under tariffs approved by the Commission, the Commission has not yet decided what kind of tracking of these costs by the shippers would be permitted. For example, the tracking provision could require a periodic rate filing under Section 4 reflecting only the change in transportation cost, similar to the shipper's current purchased gas cost adjustment clauses. Or the provision could permit the shippers to adjust their rates automatically on a simultaneous basis to reflect changes in ANGTS transportation costs. Such a provision would be similar to fuel cost adjustment clauses permitted in rate schedules and tariffs of electric utilities for transactions which are subject to this Commission's jurisdiction.

It should also be noted that no decision has yet been made by the Commission governing pass-through by the shippers of transportation costs incurred under tariffs subject to the jurisdiction of Canadian authorities.

circumstances, the shippers could be subject to under recovery of the Alaskan Northwest transportation costs because of the same regulatory lag discussed above.

(e) If additional reserves of natural gas were found in Alaska sufficient to lengthen the economic life of the ANGTS beyond the 25-year life now inherent in the proposed depreciation rate, the Commission might at some future time reduce the depreciation rate so as to more accurately spread the recovery of the plant investment over the useful life of the project. 21/ Alaskan Northwest might oppose such a change on the ground that the resultant reduced amount of depreciation expense recovered on an annual basis would impair their ability to service debt having a shorter term.

(f) In the event of a premature end to the viability of the project after it had commenced operation (because of physical, market or other forces), the Commission might find that a faster write-off of debt was appropriate, rather than continued operation of the minimum bill provisions. This could cause financial harm to Alaskan Northwest if the debt-holder refused to allow Alaskan Northwest to accelerate repayment of its debt, particularly if the interest rate to be paid to the lenders on the debt is higher than the general level of interest rates being paid for comparable investments. Alternatively, absent a waiver, a future Commission could determine, based on either a change in policy perception or based on facts attributing fault to the sponsors for the project failure, that the sponsor-investors (as opposed to the consumers) should bear some part, or all, of the risk of loss of recovery of debt, and then appropriately adjust the tariff or minimum bill provisions.

(g) In the event that Alaskan Northwest transportation costs and the costs of Prudhoe Bay and other natural gas, increase significantly, a shipper's resale rate could be increased so as to adversely affect the marketability of a shipper's gas. Under this scenario, the shippers (particularly the non-sponsor shippers) might argue for a reduction in the Alaskan Northwest transportation charges so that the shippers could continue to market their gas. Absent a waiver the Commission would have the power to

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21/ See, Memphis, Light, Gas and Water Division v. FPC, 504 F.2d 225 (D.C. Cir. 1974).

order some sort of temporary or indefinite reduction to Alaskan Northwest's charges. In response, Alaskan Northwest, or some other party, might argue that the reduction in Alaskan Northwest's charges (regardless of the reason therefor) impaired the recovery of Alaskan Northwest's "minimum bill" costs and thus jeopardized the financial health of the project.

(h) Another hypothetical involves the pipeline-shippers' current purchased gas cost adjustment (PGA) clauses, which, as now written, would permit the shippers to pass through Alaskan purchased gas costs to their customers. If the Commission should decide to revoke or modify the PGA clauses, the shippers would be subject to regulatory lag in recovering Alaskan and possibly other purchased gas cost increases. To the extent that such a lag caused a financial strain on the shippers, it could affect the cash flow to the ANGTS.

(i) In Order No. 31, the Commission stated its intention to periodically review Alaskan Northwest's rate of return on common equity. Absent the waiver, the Commission's authority to conduct such periodic reviews would provide a basis to adjust the return on common equity downward to reflect any lowering of the cost of common equity to Alaskan Northwest. Such a lowering of common equity costs would most likely result from a general overall improvement in the economy resulting in an improvement in the financial markets, leading to a reduction in the return on equity needed by Alaskan Northwest to continue to render adequate service in the public interest. The argument that a reduction in equity return could impair collection of all debt costs in violation of the proposed waiver language would presumably be an argument by lenders and others that the interest coverage must be greater than one (i.e., 1.5, 2.0, etc.) in order to ensure that Alaskan Northwest's ability to pay debt is not impaired.

11. Hypothetical Injuries to Consumers

You have asked "what hypothetical situations there might be which would work to the injury of resale customers and consumers should the waiver be granted." At bottom the most injurious risk that could be borne by the consumer is that the project might be abandoned either before or after completion, and that the consumer, through the resale customer, would be surcharged for the investment in the project but would not receive gas from it. Next most injurious is the risk that the consumer will have to pay for gas not received during sustained periods in which the pipeline is out of service. Arguably, for each risk which would exist to the sponsors and/or shippers in the absence of a waiver, there would exist a concommitant risk to the resale customers and/or consumers in the event a waiver is granted. However, in fairness these risks should be properly placed in the context of the facts of the proceeding and the legal status of the ANGTS project to date.

President Carter in his formal Decision, the Congress in its approval of the President's Decision and international agreements, and the Commission in its Recommendation to the President and in existing orders, have each concluded that this project is in the public interest. These approvals have led to the existing tariff, minimum bill and other provisions applicable to the ANGTS as described above. The project sponsors and lenders have nonetheless responded by seeking further assurance that the unique features of these determinations, as well as the Commission's final orders and rules, will not be altered or modified after adoption. Relevant here are the existing decisions of various authorities that the ANGTS may be project financed and that certain portions of the investment should be recoverable from consumers in events, including project interruption, where consumers do not receive the benefit of delivered gas. Thus, decisions have been made that impose risk on the consumers regardless of the waiver. Further, the Commission's ultimate orders and rules will allocate the remaining risks among the parties after consideration of all factors consistent with or affecting the public interest. Accordingly, an argument can be made that once the legal foundation for the ANGTS places the risks, the waiver would impose no substantial additional risk on the consumers, but only provide a method for assuring implementation of the federal decisions made. The extent to which a waiver would place additional onus on the consumers would include the implications of removing the "regulatory risk" from the sponsors. In other words, the consumers would then face the risk that a future Commission could not, based on changed circumstances or different policy perception, modify the ultimate ANGTS orders or rules within the parameters of their final issuance.

12. Reasonable Likelihood of These Events Occurring

From a legal standpoint, the likelihood that a future Commission would take or decline to take action of the type inquired about in your letter would appear to depend upon (a) whether a reconsideration of past policy determination occurs, and/or (b) the future existence of facts which would produce a policy response by the Commission. The likelihood of such facts occurring is a prediction or assessment that, presumably, has been made in connection with all federal determinations to date. In issuing the final orders and rules, the Commission is legally charged with the responsibility of weighing the risks, to both the sponsors and consumers, attendant to investing the sums necessary to complete the project. The risks are exceptionally difficult to quantify because of the infinite set of variables that exist, and in the end the question is one of judgment. Either the risks are too great for the consumers to be asked to bear (i.e., the project is not in the public interest), or they are not. The Commission may well be required to make that determination as part of its final certification of the project. 22/ Appropriately, the Congress must decide, through adoption or rejection of the waiver, whether to eliminate the "regulatory risk" inherent in continued Commission jurisdiction after final certification.

I am advised by the Chairman that he will support passage of a waiver designed to assure project financing of the ANGTS consistent with the positions expressed in this memorandum. 23/

22/ See President's Decision, Finance Condition No. 2, at pages 36-37.

23/ In this connection, the text of the ultimate waiver language, if any, is a matter of continuing interest to the Chairman, myself and the Office of the General Counsel. Without addressing any of the complexities involved with the final language, please be advised that we would welcome the opportunity to provide your Committee and other interested persons with any technical assistance or advice that may be requested.

Hopefully the foregoing provides you with an adequate response to your inquiry given the length of time taken and the resources available to prepare this memorandum. Please understand that this response is not intended, nor should it be taken, as an official Commission position. Rather, this memorandum represents the combined efforts of the Office of the General Counsel and other Commission staff members, as well as opinions of the Chairman and myself.

APPENDIX K

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 Section 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

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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.

application of Section 5, Condition IV-2 of the President's <u>Decision</u> to the gas conditioning plant; and

Section 5, Condition IV-3, of the President's <u>Decision</u>; <u>provided</u>, 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 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 operation; 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., 2nd 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 pipeline 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 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.

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* 15 U.S.C. § 717

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.

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* 42 U.S.C. § 6201, _et seq_.