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Commerce Building, San Antonio, Texas 78205. This Supplemental Remedial Order charges T–C Oil Company with pricing violations in the amount of $1,150,852.95 caused by T–C having made sales of crude oil at prices in excess of those permitted under the Federal Energy Administration (now the DOE) price rule in 10 CFR 212.73. ERA maintained that the overcharges were the result of T–C's characterization of certain "old" crude oil as "new" and "released" crude oil based upon T–C's interpretation of the term "property."

A copy of the Supplemental Remedial Order, with confidential information deleted, may be obtained from Wayne I. Tucker, District Manager, Southwest District Enforcement, Department of Energy, Economic Regulatory Administration, P.O. Box 35228, Dallas, Texas 75235, or by calling (214) 749–7626. On or before June 15, 1979, any aggrieved person may file a Notice of Objection with the Office of Hearings and Appeals, 2000 M Street, NW., Washington, D.C. 20461, in accordance with 10 CFR 205.193.

Issued in Dallas, Texas, on the 22nd day of May, 1979.

Wayne I. Tucker,

District Manager, Southwest District Enforcement.

[FR Doc. 79-16875 Filed 5-30-79; 8:45 am]

BILLING CODE 6450-01-M

Federal Energy Regulatory Commission

Advisory Committee on Revision of Rules of Practice and Procedure, Subcommittee on Ex Parte and Separation of Functions Meeting

May 25, 1979

Pursuant to provisions of the Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770), notice is hereby given that the Subcommittee on Ex Parte and Separation of Functions of the Advisory Committee on Revision of Rules of Practice and Procedure will meet on Friday, June 1, 1979 from 1 p.m., at the Federal Energy Regulatory Commission, 825 N. Capitol St., N.E., Hearing Room C, Washington, D.C. The urgency of the subject matter of the Subcommittee's work as well as the unavailability of Subcommittee members after June 8, 1979 requires scheduling of this meeting on June 1, 1979 notwithstanding the abbreviated notice period.

The purpose of the meeting is to prepare a report of the Subcommittee's recommendations concerning *ex parte* and separation of function matters. It is anticipated that the Subcommittee Report will be presented to the full Advisory Committee at a meeting which has been scheduled for June 8, 1979.

The meeting is open to the public. A transcript of the meeting will be available for public review and copying at FERC's Office of Public Information, Room 1000, 825 N. Capitol St., N.E., between the hours of 8:30 a.m. and 5:00 p.m. Monday through Friday except Federal Holidays. In addition, any person may purchase a copy of the transcript from the reporter.

Kenneth F. Plumb,

Secretary.

[FR Doc. 79-16983 Filed 5-30-79; 8:45 am]

BILLING CODE 6450-01-M

[Docket No. CP78-123 et al.]

Alaskan Northwest Natural Gas Transportation Co.—Pipeline Design and Capacity; Notice of Delegate Report and Order Inviting Comments

Issued May 17, 1979.

The Commission is issuing for comment a report submitted to it by its Alaskan Delegate. The report discusses the pipeline size and operating pressure for that segment of the Alaska Natural Gas Transportation System (ANGTS) which is to be constructed in Alaska by the Alaskan Northwest Natural Gas Transportation Company. In addition to other applicable law, this order is issued pursuant to the mandate of Section 9 of the Alaska Natural Gas Transportation Act, 15 U.S.C. § 719(g), and the President's *Decision and Report to Congress on the Alaska Natural Gas Transportation System (Decision)*, which mandates expeditious resolution of the matters discussed in the Delegate's report.

A. Background

On March 2, 1979 the Alaskan Northwest Natural Gas Transportation Company (Alaskan Northwest) filed with the Commission an application for an order to approve design specifications and initial system capacity for that portion of the ANGTS which is to be built by the applicant.[1]

Pursuant to Commission regulations, notice of the application was issued on March 16, 1979. Alaskan Northwest requests prompt action on its application so that it may proceed with steps necessary to financing and constructing the portion of the ANGTS for which it is responsible.

The Alaskan Delegate has submitted to the Commission a report concerning the diameter and maximum allowable operating pressure of the pipeline which is the subject of Alaskan Northwest's application. With respect to the design of the gas pipeline, the Delegate's report states that a 48-inch diameter was determined under the terms of the *Decision*. The Delegate's report states that with respect to the issue of what the maximum allowable operating pressure of the pipeline should be there is a threshold question: given the extensive record already compiled in this proceeding,[2] whether significant new evidence is available on likely throughput volumes from the North slope which would be served by this system since the time of the *Decision* that would suggest that an operating pressure of greater than 1260 psig should be authorized. The Delegate states that he believes there is no new information and that the Commission should authorize a maximum allowable operating pressure of 1260 psig for the pipeline.

The Commission is issuing the Delegate's Report for comment by all parties of record in this proceeding.[3] Comments should be filed by July 2, 1979. The parties may also file comments on Alaskan Northwest's application of March 2, 1979. Any party of record perceiving the need for a hearing to determine either the diameter or the maximum allowable operating pressure of the gas pipeline which is the subject of Alaskan Northwest's application should file a request to that end, by July 2, 1979, specifying the issues to be presented for determination and a brief summary of the evidence which the requesting party would present. The request should include a statement of all issues of material fact allegedly in dispute, and provide a reasonable justification as to why these issues cannot be fairly and adequately resolved on the basis of the record compiled before Judge Litt, the President's *Decision*, and the Delegate's Report.

Finally, the Commission notes that the sole issues that it intends to resolve through the procedures set forth below are: (a) the pipe diameter, and (b) the operating pressure, of the Alaska

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[1] The portion involved is that segment of the ANGTS described in the President's *Decision* as lying within the State of Alaska. *Decision* at 6–7.

[2] That record includes the *Initial Decision* of the Commission, *In re El Paso Alaskan Co., et al.*, Docket No. CP75-96, *et al.* (Feb. 1, 1977), FPC *Recommendation to the President* (May 1, 1977), and the *Decision*.

[3] A copy of the Delegate's report is attached to this order. The views expressed therein do not necessarily reflect the views of the Commission

pipeline segment discussed herein. In particular, the Commission does not intend to decide, on the basis of comments filed in response to this order, the issue of the appropriate CO_2 standard for the gas transported through the ANGTS.

The Commission orders: (1) The Alaskan Delegate will serve copies of this Order, and of his report, on all parties to Docket Nos. CP78–123, *et al.*

(2) Parties of record in Docket Nos. CP78–123, *et al.* may submit comments on the Alaskan Delegate's report, and on the March 2, 1979 application filed by Alaskan Northwest Natural Gas Transportation Company. Such comments may be filed on or before July 2, 1979, and should be served on all parties of record in Docket Nos. CP78–123, *et al.* The comments may address any issue of fact, law or policy pertinent to the matters raised in the report and the application.

(3) Any party of record in Docket No. CP78–123, *et al.* may file, on or before July 2, 1979, a request for an evidentiary hearing to determine the diameter or maximum allowable operating pressure of the gas pipeline described in Alaskan Northwest's March 2, 1979 application. Such request must specify the issues to be presented for determination at such a hearing, including a statement of all issues of material fact allegedly in dispute; a brief summary of the evidence that the requesting party would present; and a reasonable justification as to why such a hearing is necessary and why the issues cannot be fairly and adequately resolved on the basis of the record compiled before Judge Litt, the President's *Decision*, and the Delegate's Report. Copies of the request should be served on all parties to Docket Nos. CP78–123, *et al.*

By the Commission.

Kenneth F. Plumb,

Secretary.

Report of the Alaskan Delegate on the System Design Inquiry

I. Introduction

In his *Decision and Report to Congress on the Alaska Natural Gas Transportation System* the President said, "[t]he gas transportation system will utilize a 48-inch diameter pipeline from Prudhoe Bay to James River, Alberta * * *"[1] except as "* * * modifications to those facilities are required by the Agreement on Principles between the U.S. and Canada * * *." [2] The *Decision* also said, "[the] facilities * * * are those in the U.S. which are adequate for a throughput of up to 2.4 [billion cubic feet per day] bcfd and are included in the revised Alcan filing submitted to the Federal Power Commission (FPC) in [sic] March 8, 1977." [3]

The report which accompanied the *Decision* went on to say, however, that—

* * * Alcan should consider increasing the operating pressure and wall thickness of its 48-inch diameter pipeline in order to allow for more efficient increases in throughput rate for additional reserves which might be committed to the system from either Alaska or Canadian sources.[4]

The report also noted that—

Overall, considering the arctic construction, inflationary impacts and environmental impacts, the ultimate cost to consumers of providing capacity for increased gas throughput would be much lower if the capacity is provided initially by increasing the diameter or working pressure of the pipe, than if it is provided later by adding compressor horsepower or looping the pipeline.[5]

After observing that the Agreement with Canada provides for use by Canada of the main line at a throughput up to 1.2 bcfd, the report concluded "* * * redesign of the system to enable inexpensive expansibility up to 3.9 to 4.0 bcfd south of Whitehorse, Yukon Territory, is essential."[6]

Accordingly, the Agreement on Principles provided for installation of a higher capacity system than that which had been proposed by the project sponsors for the segment which is to carry both U.S. and Canadian gas volumes, to be installed between Whitehorse, in the Yukon Territory, and the bifurcation point at James River, Alberta. The Agreement also provided for a technical study group to evaluate the alternative higher capacity systems which had been discussed by negotiators for the two countries in the course of reaching the Agreement.

U.S. and Canadian government technical representatives began meeting soon after the U.S. Congress approved the *Decision*. U.S. representatives favored a 48-inch pipeline system with a higher maximum allowable operating pressure, 1680 pounds per square inch guage (psig). They thought that the higher pressure system would require an increased investment, but would be more fuel-efficient than one of lower pressure.[7] For their part, Canadian representatives consistently expressed reservations about safety and reliability aspects of the higher pressure system, and the accuracy of the capital cost estimates for it, since it represented a greater technological step away from the present level of maximum operating pressures, which is about 1100 psig. Their preference was always for a larger diameter alternative with the same or slightly lower operating pressure.[8]

Due to the nature of their reservations and the risk of possible delays associated with testing the higher pressure system, the Canadian National Energy Board (NEB) chose a 56-inch diameter, 1080-psig system for the joint-use section. Consistent with all prior statements, their Statement of Position evidenced considerable concern over the safety and reliability aspects of the high-pressure design, plus concern over the adequacy of cost estimates and construction schedules for that system due to increased technological risks.

The Canadian decision also had the effect of narrowing somewhat the options for system design north of the joint-use section, compared to what the options might have been at the time of the *Decision*.[9] The options for the segment north of the Whitehorse then became the 1260-psig system proposed by the sponsoring companies, or a thicker walled 48-inch pipeline which would operate at a higher pressure.[10] The higher pressure choices seem to be the 1680 psig system, which had been the design of one of the competing proposals and has been favored by two of the three principal North Slope gas producers, and (2) an intermediate design which would operate at between

[1] *Decision and Report to Congress on the Alaska Natural Gas Transportation System*, p.13. Herein referred to as "the *Decision*."

[2] *Ibid.*

[3] *Ibid.*

[4] Report accompanying *Decision* at 193.

[5] *Ibid.*, p. 104.

[6] *Ibid.*, p. 190. "The system" in this context refers to Alcan's March 8, 1977, proposal; the redesign south of Whitehorse refers to the agreement with the Canadian Government to use a higher capacity system between Whitehorse and the bifurcation point.

[7] At higher throughput volumes, the fuel savings more than offsets the increased investment costs of the higher pressure system, resulting in lower unit transportation charges.

[8] Increasing the diameter of the pipeline system for a given operating pressure and throughput rate also increases operating efficiency. However, for the alternative systems evaluated by the technical study group, the larger diameter systems were consistently less fuel-efficient than the higher pressure system. Furthermore, the capacity of the larger diameter systems to carry natural gas liquids (NGL's) is less than that of the higher pressure one for any given operating temperature.

[9] The ability of the 56-inch system to transport NGL's limits the NGL's content in the gas stream delivered to it. Thus, increasing system pressure to increase NGL's carrying capacity is pointless beyond the limit imposed by the 56-inch system.

[10] Section 3 of the *Decision*, "Identification of facilities included within 'Construction and Initial Operation'", specifically references a 48-inch diameter pipeline from Prudhoe Bay to James River, Alberta except as modifications are required pursuant to the Agreement on Principles Between the U.S. and Canada.

1400 and 1440 psig. As the lea[illegible] time associated with full evaluation of either of these higher pressure alternatives could also affect the schedule for project implementation in this country, the Alaska Gas Project Office (AGPO) undertook this inquiry in an effort to facilitate a final FERC decision on the maximum allowable operating pressure.

Our process for studying the pressure question was to discuss it with interested parties and to prepare independent calculations of the expected transportation costs at different throughput rates, utilizing the alternative system configurations. We issued a draft report on the system design on September 27, 1978. We then provided a period for comments on the draft report and held an on-the-record conference among interested parties on December 15, 1978. At that conference I developed a proposition for resolution of the pressure question which served as the basis for the project sponsors' filing of March 2, 1979.[10]

This report summarizes the positions of the parties as expressed in our discussions with them, their comments on our draft report, and their remarks at the conference. It then presents the AGPO's findings and relevant findings in the *Initial Decision* in *El Paso Alaska Company, et al.*, Docket No. CP75-96, *et al.* (hereinafter referred to as the *Initial Decision*), the FPC *Recommendation to the President*, and the *Decision*.[11]

After my draft report had been circulated and comments initially solicited, a study of the required sales gas conditioning facility,[12] sponsored by a group of producers and pipeline companies, was made available to me. This study has not been formally filed with the Commission, nor evaluated by other experts. However, I believe it to be the most authoritative and accurate compilation and analysis of information available on the requirements for processing [illegible]nd conditioning the Prudhoe Bay gas, a[illegible] on the characteristics of the sales g[illegible] stream. As the report was made available to me in my capacity as the Commission's Alaskan Delegate, it appears in my public file and is available for inspection by any interested party or member of the general public in the Commission's office of Public Information.

The results of the study clarified certain concerns, and obviated others, particularly with respect to the dispostion of the natural gas liquids (NGL's). I have maintained my description of the concerns expressed to me, but have tried to note the impact of the study results on those concerns as appropriate. I have also added a section to this report which applies the results of the study to the questions being considered here.

II. Positions of Interested Parties[13]

1. *State of Alaska.* Alaska conditionally supports a pipeline with a maximum operating pressure of 1260 psig.[14] Its support is conditioned upon the validity of certain assumptions mentioned in its comments on the project sponsors' March 2, 1979, application, all of which I believe to be true.

The State's principal objectives as expressed to us concerned the development of an instate manufacturing base to smooth out the "boom or bust" cycles of raw materials production industries. In the case of its Prudhoe Bay hydrocarbon resources, the State would like to develop a capability to convert some of these hydrocarbon resources into semi-finished and finished products. The State has previously used agreements for the sale of its royalty oil to encourage construction of additional refinery capacity in Alaska. An idea being discussed by State officials was development of a capability to manufacture various petrochemicals, which use produced NGL's as feedstocks.

The State contracted with the consulting firm of Dames and Moore for an analysis of the possibility of a world scale petrochemicals plant to be located in Fairbanks. The petrochemicals facility chosen for study would use ethane as a feedstock. At the time we talked with State officials, the State had no specific plans for utilization of propane and heavier NGL's but expressed a willingness to develop such plans if required to achieve their objectives with respect to in-state use of some of the Prudhoe Bay resources.

Additionally, State authorities expressed an interest in maximizing recovery of the total energy resources of the Prudhoe Bay deposit. The modes of disposition of produced hydrocarbons are:

(1) Transportation through the oil pipeline or a new NGL's pipeline,

(2) Transportation through the gas pipeline,

(3) Use within the field as fuel for production and processing and conditioning facilities,

(4) Fuel use for pump stations on the oil line and compressor stations on the gas line,

(5) Reinjection, and

(6) Some combination of the above.

The distribution of the NGL's among these various dispositions is a function of the designs of the oil pipeline and the gas pipeline, and of production and processing and conditioning facilities on the North Slope. It will not be completely settled until the designs for all of these facilities have been finalized. State officials expressed an interest in transportation of the NGL's away from the North Slope in order to deliver them to higher value uses. State officials were also concerned that any disposition of gas or NGL's by reinjection involves some loss of ultimate recovery of that which is reinjected.[15]

Although the increased ability of the higher pressure alternatives to transport NGL's might make Alaska favor higher pressure, other aspects of the State's overall concerns might incline them toward the 1260 psig system.

This concern is over the impact of gas production on oil recovery. The State conservation authority now expects that there will be sufficient gas available for sale from the Prudhoe Bay Main Pool Reservoir to support gas sales of 2.0 [illegible]. [illegible] small possibility that actual production history of the reservoir will require a reduction in the level of [illegible]. As the possibility is small, and I would occur through circumstances which cannot

[10] See "Application of Alaskan Northwest Natural Gas Transportation Company For An Order Approving the Design Specifications and Initial System Capacity of the Alaska Segment of the Alaska Highway Pipeline Project," filed in Alaskan Northwest Natural Gas Transportation Company, Docket No. CP80-[illegible] *et al.* on March 2, 1979. This application was noticed by the Commission on March 12, 1979.

[11] [illegible] the present [illegible] part [illegible] AGPO's effort to "expedite" [illegible] completion [illegible] the necessary [illegible] which the Commission will require before it can [illegible] analyze [illegible] the future applications for permanent certification [illegible] required by the Commission by order of December [illegible].

[12] "Sales Gas Conditioning Facilities, Prudhoe Bay, Alaska," The Ralph M. Parsons Company, September, 1978 Study Report. The sponsors were 7 producing companies and 11 natural gas transmission companies. The study is referred to herein as "the Parsons study."

[13] During the course of our meetings with interested parties, most submitted written materials, [illegible] in response to our request. All of these [illegible] the draft report, which was circulated to all parties in Docket Nos. CP[illegible] *et al.* and to [illegible]. Those [illegible]. [illegible] Order of December [illegible].

[14] Opening [illegible] of the State [illegible] on the Design Specifications and Initial System Capacity of the Alaskan Segment of the Alaska Highway [illegible] Project filed in Alaskan Northwest Natural Gas Transportation Company, Docket Nos. CP80-[illegible] *et al.*

[15] [illegible] could [illegible] oil recovery [illegible] studies [illegible] that [illegible] the same amount of energy could be consumed in the reinjection process as would be provided by the additional oil recovered.

now be foreseen. State authorities cannot say with precision what allowable gas production might be in the event that production experience requires reduced gas sales. Reduced availability of gas would argue for a lower capacity transmission system.

Our principal discussions on these issues with Alaska State officials took place in early February, 1978, before the Canadian Government's decision to utilize the 56-inch, 1080 psig system for the Whitehorse-to-James River segment. Prior to that decision, some consideration was given to a very high pressure (2150 psig) system proposed by Exxon in order to eliminate the need for any gas processing and conditioning facility at the producing area on the North Slope. Moving the processing and conditioning facility to somewhere south of Prudhoe Bay was suggested so as to locate it where costs were less than at Prudhoe Bay. Colocation of such a facility with a petrochemicals manufacturing facility was thought possibly to yield some economies of scale for construction of both. As the State's economic analysis of petrochemicals development was observed to be very sensitive to feedstock costs, we thought that any colocation economies might improve the State's prospects for petrochemicals development. Because of this interest, we discussed the possibility of moving the processing and conditioning facility away from the North Slope with representatives of the North Slope producing companies. These discussions are summarized below.

Alaska observed that a 1400 psig or 1680 psig system can carry a higher percentage of the butanes in the gas phase than a 1260 psig system, other things being equal. Butanes raise the Btu value and, thus, the heating value of the gas. With respect to the disposition of the butanes through the oil pipeline, Alaska noted that California air quality regulations restricting the vapor pressure of crude oil could limit the butane content of crude oil. Because of the potential for air pollution, the vapor pressure of all crude oil entering California must be held to a very low level unless vapor recovery systems are installed for oil storage facilities. Injecting butane into the North Slope crude oil has the effect of increasing its vapor pressure at any given temperature. Keeping the vapor pressure down after butane injection requires cooling the oil which, in turn, could cause wax formation problems in the oil pipeline.

2. *Standard Oil of Ohio (Sohio).* Sohio believes that the maximum operating pressure should be 1260 psig.

At the time of our discussions with Sohio (March 15, 1978), the Canadian Government had made its decision to utilize the 56-inch, 1080-psig system for the Whitehorse-to-James River segment. Due to the hydrocarbon dew point characteristics of the gas stream at those operating conditions, the Canadian decision imposed a requirement for some NGL's removal prior to introduction of the raw gas stream into that Canadian portion of the system. The requirement for some processing and conditioning north of Whitehorse limits the question of where all processing and conditioning should take place.

The Sohio representatives maintained that, although construction costs on the North Slope are high, they are probably lower there than anywhere in inland Alaska, and probably also lower than anywhere in the Yukon Territory. The difference is that coastal locations can be served by barges transporting any large facility in modules, whereas an inland location requires transporting much smaller components with a concomitant requirement for much more extensive onsite assembly.[17] According to Sohio, very large processing and conditioning facilities can be constructed and loaded onto barges in the lower 48 states, where complete fabrication facilities are available and assembly costs are much lower. Any inland Alaska or Yukon location would preclude the use of large modules and would require construction from components small enough to be loaded onto railroad cars or trucks for transportation to the inland location. Assembly of the small components would then have to be done in remote locations of Alaska or the Yukon. The difficulty of extensive assembly in remote locations makes inland locations less competitive with coastal locations. Sohio concluded that, because of the ability to make full use of economies of scale in designing the facility and modularizing it for transportation, the cost of facilities would probably be less for Prudhoe Bay or another coastal location than for any inland location.

Having concluded that Prudhoe Bay is the optimal location for any facility required to be located along the pipeline route north of Whitehorse, the next question was how much of the processing and conditioning should be done there. Except for the very high pressure (2150 psig) alternative proposed earlier by Exxon, transportation of the CO_2, which comprises about 12 percent by volume of the unconditioned gas, is not cost effective according to Sohio.[18] The savings in gas conditioning costs made possible by leaving the CO_2 in the gas is more than offset by the reduced transportation efficiency for the other components of the gas caused by the presence of the CO_2. As the very high pressure system (2150 psig) had been ruled out by the Canadian Government's decision for the Whitehorse-to-James River segment, CO_2 removal is required north of Whitehorse and consequently should be done at Prudhoe Bay.

Once the CO_2 is removed, the ability of the gas stream to transport NGL's is reduced. Thus, operating the gas pipeline system without condensation would require some NGL's removal as a consequence of the decision to remove the CO_2, regardless of whether the 1260 psig or one of the higher pressure alternatives is utilized. The difference between the required processing and conditioning for the 1260 psig and 1680 psig alternatives is in the degree of NGL's removal. The requirement for the 1430 psig system is between those of the 1260 psig and the 1680 psig systems.

The advantages of modular construction suggest that, since some processing is required on the North Slope, it is most cost-effective to do all of it there. The CO_2 produced in the course of conditioning the gas may be able to be utilized in combination with extracted NGL's as a low Btu fuel to power field production operations, processing and conditioning plant operations, or perhaps pumping or compressor stations.[19]

The Sohio representatives saw little to be gained by increasing the operating pressure of the gas pipeline to 1680 psig. They saw no major processing and conditioning savings projected for the 1680 psig system, but additional compression costs would be substantial. Although it is possible that compression

[17] Modular construction not only allows assembly of a facility at a location where costs are lower, but also allows the use of very large processing vessels, enabling realization of considerable economies of scale in facility design and operation. The Parsons study provides some further discussion of the benefits of modular construction.

[18] In its comments on the draft report Alaska argued that it is cost effective to leave at least 3 percent of the CO_2 in the gas stream. A 3 percent standard, according to Alaska, would save 10 percent of the capital costs of the conditioning plant and could result in a reduction of the cost of service to the consumer by noticeable amounts. See also Notice of Proposed Rulemaking and Statement of Policy, Docket No. RM78-10, issued February 2, 1978, wherein the Commission proposes a policy by which producers shall bear the costs of conditioning facilities rather than consumers.

[19] This possibility is developed in some detail in the Parsons study.

facilities other than those currently used as part of oil production would not be required for operations at 1260 psig,[20] additional compression capacity would have to be installed to attain the higher pressure, and operating costs would be significantly increased.

On the other hand, the Sohio representatives felt that the 1260-psig gas pipeline design, plus slight alterations to the oil pipeline, if required, were the most cost-effective solutions to the problem of moving the NGL's. The pentanes and heavier hydrocarbons could be moved through the oil pipeline essentially without alterations; the propanes and lighter hydrocarbons would go through the gas pipeline at 1260 psig. Sohio maintained that between 62 and 75 percent of the butane could be moved through the gas pipeline with the 1260-psig design.[21] Cooling the oil line would be the only alteration required to move the rest of the butane.

Some cooling of the oil line is expected to be required when its throughput capacity is increased from 1.2 million to 1.5 million barrels per day. Sohio argued that the relatively small additional capital investment for additional cooling to allow transporting butanes, plus the very low operating cost of the cooling facilities, would make transportation through the oil line the more cost-effective solution for the remaining butane, particularly when compared to the high investment and operating cost for extra compression to 1680 psig. The extra cooling required to accomodate the butane would be less costly if installed at the time of the increase in oil line throughput capacity.

3. *Atlantic Richfield Company (ARCO).* Arco representatives confirmed what we had heard from Sohio regarding the possibility of moving some or all of the required gas processing facilities away from Prudhoe Bay. It was their view that the decision in Canada to use larger diameter pipe for the Whitehorse-to-James River segment precluded the use of the very high pressure alternative, for which the North Slope processing and conditioning facilities could have been eliminated. Thus, moving any of the required processing and conditioning steps south of Prudhoe Bay would result in some duplication of facilities, as removal of both CO_2 and most NGL's would be required somewhere north of Whitehorse. Arco representatives also concurred with Sohio's judgment that the savings available through modular construction would overwhelm any potential savings in moving facilities to inland locations with slightly more hospitable climates. Their estimate was that construction costs in Fairbanks or Haines, Alaska, would be as much as 50 percent higher than those at the North Slope because of the impact of modular construction.

The Arco representatives were concerned about the ability to dispose of the produced butanes if the lower pressure gas pipeline system were utilized. Their concerns were in the following three areas:

(1) Crude oil vapor pressure limitations in California. (See p. 8 *Supra*.)

(2) The west coast market for petroleum products cannot use additional large quantities of butane.

(3) In considering use of a blend of CO_2 and NGL for field fuel, the Arco representatives suggested that propane was a much better blending stock for the CO_2 than butane. Extremely close Btu control is required for efficient turbine operation, and Arco technical personnel expressed concern over possible problems with condensation in fuel lines and burner orifices if butane were to be used.[22]

The Arco representatives also had some different figures on the ability of the alternative gas pipeline systems to carry butane. Their figures showed the 1260 psig system would carry 25 to 60 percent of the available butane, while the 1680 psig system would carry 50 to 98 percent of the available butane.[23]

We asked some questions about alternative investment costs under different possible gasline system configurations. The figures we received suggested that a reduction in system operating pressure from 1680 psig to 1260 psig would require an additional investment on the order of $100 million (in 1978 dollars), consisting of $30 million in increased processing and conditioning facilities, and $47 to $75 million for some combination of cooling for the oil pipeline, modifications to field fuel facilities, and reinjection facilities if required.[24]

Arco argued in its comments on the draft of this report that the increased natural gas liquid carrying capability of the higher pressure systems would benefit the consumer. Arco argued that even if the transportation costs are lower for a pipeline with a 48 inch diameter which operates at a maximum pressure of 1260 psig and which transports 2 bcfd of gas, a pipeline operating at a maximum pressure of 1440 psig would carry more butanes which would have the dual benefit of providing more Btu's to the gas consumer and reducing the volumes of butanes which would have to be disposed of less economically. Use of butane as a field fuel on the other hand, would require expensive conversion of existing fuel equipment; reservoir injection of liquid butanes could result in the ultimate loss of a significant quantity of these liquids; and transporting butane in the oil pipeline would require cooling the crude oil. Moreover, Arco argued that as long as the oil pipeline is operating at capacity, the transportation of butanes would require a reduction of crude oil shipments or an expansion of the capacity of the oil pipeline.

4. *Exxon.* Exxon has argued that the pipeleine should have a maximum operating pressure of at least 1680 psig. Exxon representatives concurred with the opinions of the other two producers that an inland location for any processing and conditioning facility would likely be more costly than locating it at Prudhoe Bay. They also confirmed that the constraint on the butane content of the crude oil is the restriction on crude oil vapor pressure for reasons of air pollution control in southern California.

Representatives of Exxon were involved in the testing associated with the evaluation of safety and design aspects of alternative pipeline system designs which was carried out by the Arctic Gas Study Group. They suggested

[20] Both Arco and Sohio pointed out in comments on this report in draft form that the raw gas compression facilities currently being utilized as part of oil production operations may continue to be required to maintain oil production even after gas sales commence. Thus, the availability of existing compression equipment for service in connection with gas sales is not assured.

[21] At the sales gas composition contemplated by the Parsons study, this proportion is even higher. See the discussion below of certain results of the Parsons study.

[22] In fact, the Parsons study concludes that propane injection into the fuel gas mixture is the optimal solution for Btu control of that stream. The sales gas mixture projected by Parsons has more capacity to transport butane than assumed by Arco, however, because of the reduced amount of propane required to be transported.

[23] See the discussion below of the Parsons study for further information on the NGL's carrying capacity of the sales gas stream.

[24] In comments on my draft report, Sohio noted that Arco's $100 million figure must not have taken into account the reduced requirement for investment in sales [illegible] compression facilities if the lower pressure gas pipeline system were utilized. Sohio's comments state: "The net differential investment which would be required in the gas conditioning facilities and in various Prudhoe Bay field facilities to be compatible with a 1260 psig pipeline system is expected to add considerably less than the $100 MM (in 1978 dollars) estimated by ARCO, even when all butanes recovered are transported in the TAPS line in preference to blending them with the sales gas. Operating costs of oil coolers are also expected to be less than those related to additional gas compression. Sohio's Comments, page 2, October 27, 1978."

to us that there was little real safety difference between the 1260-psig and 1680-psig systems. The real safety question from their perspective is the proximity of either system to the oil pipline. The principal safety issue is what would happen to the oil pipeline in the event of a natural gas explosion and fire.

Exxon's concern in the comparison between 1260-psig and 1680-psig systems was the cost-of-service advantage of the higher pressure system. They had previously advocated a very high pressure (2150 psig) system to increase the cost-of-ser ice advantage even further.

In our discussion with them, they emphasized the highly prospective nature of the Beaufort Sea area and its potential for discovery of additional gas reserves. They favor higher pressure generally because it will result in a more fuel-efficient system at all levels of throughput, and will have a higher throughput capacity with a lower cost-of-service at higher throughput volumes.

5. *Alaskan Northwest Natural Gas Transportation Company (Alaskan Northwest).* Alaskan Northwest is opposed to a pipeline with a maximum allowable operating pressure of either 1440 or 1680-psig. A major source of concern is its belief that a delay of up to 2 years could result from choosing a higher pressure system due to a need for extensive testing of the various components of such a system. The testing program required would include burst tests, test of crack arrestor designs, testing programs to validate valve designs, and lead times associated with high pressure compressor development. A delay of up to 2 years was estimated by the project sponsors to result in additional carrying charges of up to $1 billion.

Alaskan Northwest also shows a cost of service advantage for the lower pressure system at the throughput volumes they expect. The 1680-psig system does not become superior in performance until the throughput rate passes 3.6 bcfd according to its figures in its recent application.[75] Alaskan Northwest maintained that the point at which the 48-inch, 1260-psig system is equivalent in co[illegible] of service to the 48-inch, 1440-psig system is approximately 3.3 bcfd. Thus, the company concludes that the proposed system is the best economic selection up to a volume of approximately 3.3 bcfd prior to any consideration of potential delays. In its petition, Alaskan [illegible]orthwest, citing findings in the *Decision* and the FPC *Recommendation to the President*, argues that 2.0–2.5 bcfd of gas will initially be available to the system and that the system should be capable of expansion by 1.0 to 1.5 [illegible] to an ultimate system capac[illegible]n the range of 3.0 to 4.0 bcfd. In the application, Alaskan Northwest suggests that Alaska's interest in the development of a petrochemical industry should not dictate a decision in favor of a higher pressure line. Alaskan Northwest argues that the primary raw material for such a plant is ethane and that a 1260-psig system can transport all the ethane that could be available from Prudhoe Bay almost irrespective of the final configuration of any processing and conditioning plant, and therefore does not offer any impediment to the State's plans.

Alaskan Northwest maintains that the oil pipeline represents the most cost-effective way to move any available quantities of excess butane. Although an investment of up to $100 million (in 1978 dollars) could be required for additional processing and conditioning plant investment and cooling, fuel conversion or reinjection facilities, relative to what would be required for the 1260 psig system, a 1660 psig pipeline system would require $237 million more capital inves[illegible]ent (expressed in 1975 dollars) than the 1260 psig system.

Alaskan Northwest also maintains that there is plenty of room in the California market for additional butane. Its figures show that California refineries produced about 100,000 barrels per day of butane in 1975. The extra butane left on the North Slope after that which can be transported in the 1260-psig gas pipeline system would be something less than 22,000 barrels per day at a gas sales rate of 2.0 bcfd depending on the components of the sales gas stream,[76] before any allowance for field fuel uses.

Another concern expressed by the project sponsors is the additional safety hazard associated with a higher pressure system. Higher pressure causes higher potential energy to be stored in the pipe, resulting in increased likelihood of damage to the oil pipeline in the event of a gas pipeline rupture. The project sponsors maintain that crack arrestors will be required for the 1440-psig or 1680-psig system, whereas they may not be required for the 1260-psig system.

The project sponsors are also concerned about the vulnerability of the higher pressure system to cost overruns. Their submissions includes a risk analysis of various factors which are likely to cause additional cost overruns with the higher pressure system. They feel that the risk of cost overrun is greatly reduced by staying closer to existing and proven lower-48 states pipeline technology.

Finally, Alaskan Northwest reacted negatively to my proposal discussed at the conference to build a pipeline which would operate initially at a pressure of 1260 psig but whose operating pressure could be increased to 1440-psig if there were an increase in gas volumes available for transporting. It argued that a pipeline should be operated at its maximum design pressure. It also noted that delay would be caused by the need to test such a system.

6. *The U.S. Department of Transportation.* Noting that it is a basic tenet of transportation system planning that a system should be designed to accommodate future growth, the Department of Transportation (DOT) argued that all the technical and economic data appear to them to support building a 1680 psig system. Moreover, the availability of capacity resulting from the construction of a 1680-psig system would encourage development and exploration in the total North Slope area. Citing a February, 1978 Technical Study Group evaluation of the 1680-psig system,[77] DOT argued the system could be built and operated safely and reliably.

As noted above, a proposal was considered at the conference to build a pipeline the operating pressure for which would initially be 1260 psig and would be capable of expansion to 1440 psig if there were an increase in gas volumes available for throughput. The concept was to alter the compressors and the spacing of the compressor stations in order not to foreclose the possibility of increasing the operating pressure later on. DOT indicated that its safety regulations required a thicker pipe wall for a pipeline operating at 1440 psig than for a pipeline operating at 1260

[75] "Application of Alaskan Northwest Natural Gas Transportation Company for an Order Approving the Design Specifications and Initial System Capacity of the Alaskan Segment of the Alaska Highway Pipeline," *op. cit.*

[76] The extra butane would be only about 4500 barrels per day at the sales composition projected by the Parsons study. See the discussion of the results of that study presented below. The Parsons study notes that the capacity of the system to transport butane could be increased by leaving more CO_2 in the sales gas, and recommends further study of the most cost-effective sales gas composition.

[77] "U.S. Government Safety and Reliability Evaluation of Different Pipe Size and Pressure Combinations for Alaska Gas Pipeline," attached to February 14, 1978, letter from Don S. Smith, Vice-Chairman of the FERC, to J. G. Stabback, Chairman of the National Energy Board of Canada, transmitting the U.S. Government's views regarding pipe size selection for the Whitehorse-to-James River segment.

psig. and that it would be reluctant to waive these regulations where the pipeline was built along the Alyeska haul road. A substantial portion of the pipeline in Alaska will be built along the haul road.

III. Results of the Parsons Study

The Parsons study was undertaken by a group of gas producing and transmission companies [28] in order to develop a preliminary design for the facilities necessary to process and condition gas produced from the Prudhoe Bay Unit for transportation through the ANGTS. The principal tasks performed in the course of the study were:

Screening the processes available and selecting processes to recommend for CO_2 removal and hydrocarbon dewpoint control, respectively, and

Developing a process design for processing and conditioning the gas to meet an assumed set of pipeline delivery conditions and quantity and quality specifications.

The study represents a careful evaluation by a consultant to a group composed of both producers and transporters of the optimal distribution of the components of the raw gas stream, for conditions as they currently exist or are expected to exist, among field and process fuel uses on the one hand, and the sales gas stream on the other. The relevance of the study to this inquiry is in the study's indicated resolutions of questions regarding the optimal allocation of the NGL's and the impact of those resolutions on the requirement to transport NGL's away from the North Slope. The study team concluded that a physical solvent process is best for CO_2 removal. A characteristic of physical solvent processes is absorption of a significant quantity of hydrocarbons along with the CO_2. Much of the heavier hydrocarbon content is liquefied during the solvent regeneration process, and can thus be recovered. Significant amounts of ethane and propane remain in a gaseous phase, however, mixed with the extracted CO_2.

Because of its hydrocarbon content, the waste stream from the CO_2 removal process has useable fuel value. The study recommends that this CO_2/hydrocarbons mixture be used as fuel for the processing and conditioning facility itself. Any excess of this mixture over the requirements of the conditioning facility would be utilized in the other facilities at the Prudhoe Bay Unit after appropriate blending with other fuels (particularly propane) for heating value control.

Gas delivery and quality specifications assumed for purposes of the study were:

Delivery volume (nominal), 2.0 bcf.
Delivery Pressure, 1440 psig.
Delivery Temperature (max.), 25°F.
CO_2 content (max.), 1.0 Volume percent.
H_2S content (max.), 1.0 grain/100 SCF.
Hydrocarbon Dewpoint (max.), −10°F at 1,100 psia.
Water dewpoint (max.)., −35°F at 1,100 psia.

These specifications are similar to those which were part of the Alcan filing of March 8, 1977, except for the delivery pressure. The 1260 psig delivery pressure in that filing requires a more stringent hydrocarbon dewpoint standard, −10°F at 1,000 psia.

The results of the Parsons study with respect to allocation of recovered NGL's between fuel uses and addition to the sales gas stream is given in the following table, taken from the study itself:

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[28] Amerada Hess Corporation, Atlantic Richfield, Exxon Company U.S.A., Getty Oil Company, Mobil Oil Corporation, Natural Gas Corporation of California, Northern Natural Gas Company, Northwest Pipeline Corporation, Pacific Interstate Transmission Company (Arctic), Panhandle Eastern Pipeline Company, Phillips Petroleum Company, Sohio Petroleum Company, Southern Natural Gas Company, Tennessee Gas Pipeline Company, Texas Eastern Transmission Corporation, Texas Gas Transmission Corporation, Transcontinental Pipeline Corporation, United Gas Pipeline Company.

	Propane	Butanes		Pentanes-plus
Net Extracted				
BPD	52,350	31,290		28,700
MMSCFD (1)	80.3	41.3		--
Disposition		Min.	Max.	
To Pipeline Gas				
BPD	24,270	-0-	30,602	-0-
MMSCFD (1)	37.2	-0-	40.4	-0-
To Fuel Gas Systems				
BPD	28,080	-0-	-0-	-0-
MMSCFD (1)	43.	-0-	-0-	-0-
To Crude				
BPD	-0-	688	31,290	28,700

(1) Standard conditions - 14.5 psia and 60°F.
MMSCFD = million standard cubic feet per day.

Source: Table 6-3 from Volume I, p. 6-4.

When combined with the NGL's not recovered from the gas mixture produced by the CO2 removal process, the total allocation of NGL's between fuel uses and sales gas is estimated as follows:

Input	(Billion Btu per day)	Sales Gas	Sales Liquids	Sales Total	Field Fuel	Fuel Use as percent of Input
C1	2101.7	1909.0	0	1909.0	1[illegible]2.7	9.2
C2	323.1	163.3	0	163.3	159.8	49.5
C3	249.2	91.4	0	91.4	157.8	63.3
C4	156.2	136.1	9.5	145.6	10.6	6.8
C5-plus	125.4	5.0	119.9	124.9	0.5	0.4
	2955.6	2304.8	129.4	2434.2	52[illegible].4	17.6

Source: AGPO estimate from material balances in Parsons study

As can be seen from the table reproduced from the study, the sales gas stream will accommodate almost 98 percent of the recovered butane under the conditions assumed for the study. Reference to figure 2-1 from volume II of the study, reproduced on the next page, indicates that the 1260-psia system will accommodate 86 percent of the recovered butane, leaving only about 4500 barrels per day of butane for reinjection or transmission through the oil pipeline.

In a section entitled "Future Design Considerations" (Volume I, Section 12), the study recommended that the cost impact of possible alternative specifications for CO2 content and gas pipeline pressure be evaluated for the overall conditioning and gas transmission system. The study observed that a higher allowable CO2 content of the delivered gas will have a "significant" impact on the facilities costs. The State of Alaska has estimated that relaxing the CO2 standard from 1 percent to 3 percent would save 10 percent of the capital costs of the conditioning plant (see footnote 18, supra.). Our reading of the Parsons study would confirm this estimate.

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Case D.F Curve	Base (Max. Field Fuel) 1	2	3	4	Alt. (Min. Field Fuel) 5	6	7	8
DeC_3 Ovhd, M/H	4075	4075	4075	4075	5475	5475	5475	5475
DeC_4 Ovhd, M/H	0	2259	3398	4517	0	2115	3173	4231
DeC_4 Ovhd, %	0	50	75	100	0	50	75	100

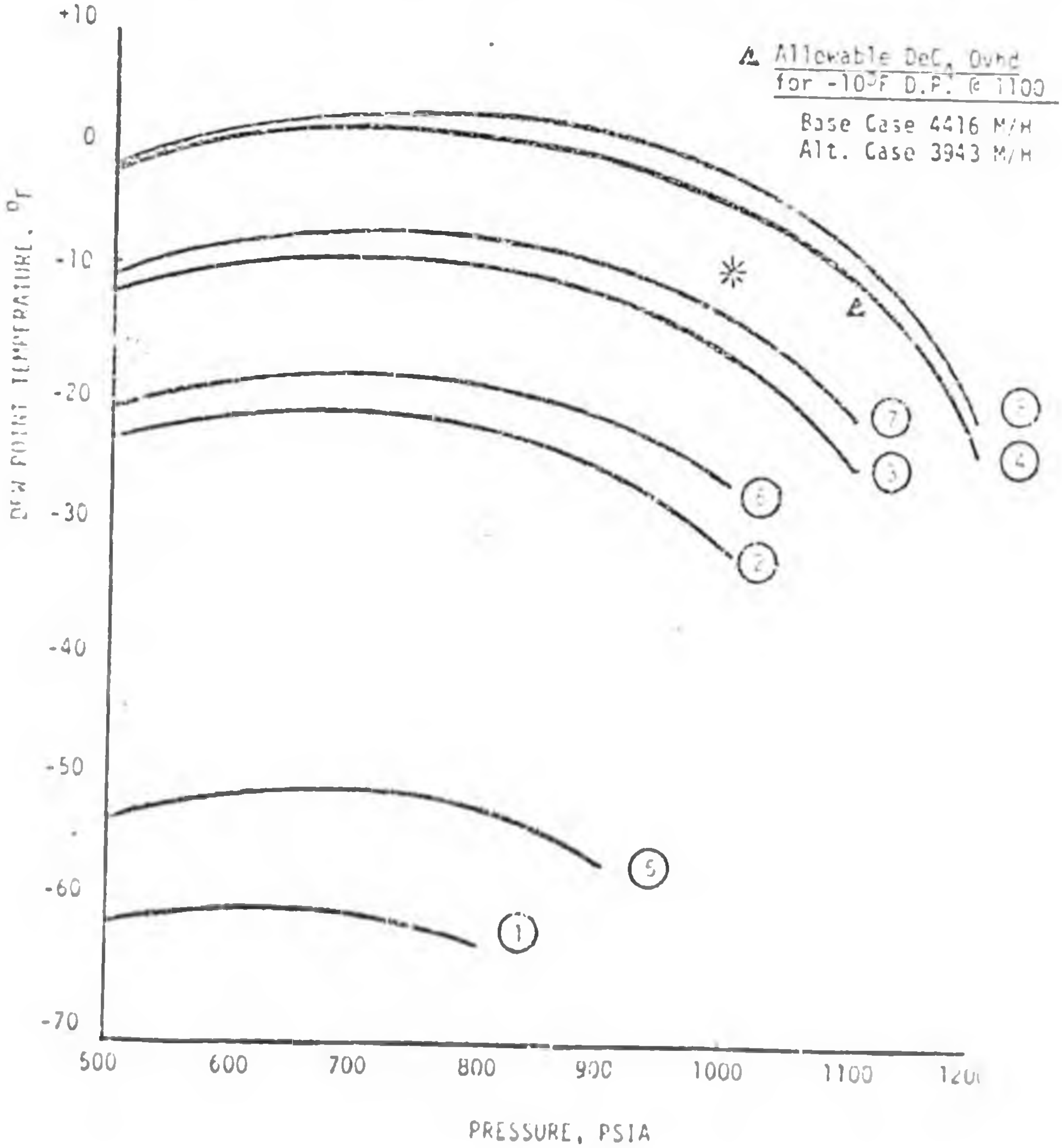

FIGURE 2-1

2-95

* - 10°F dewpoint at 1000 psia

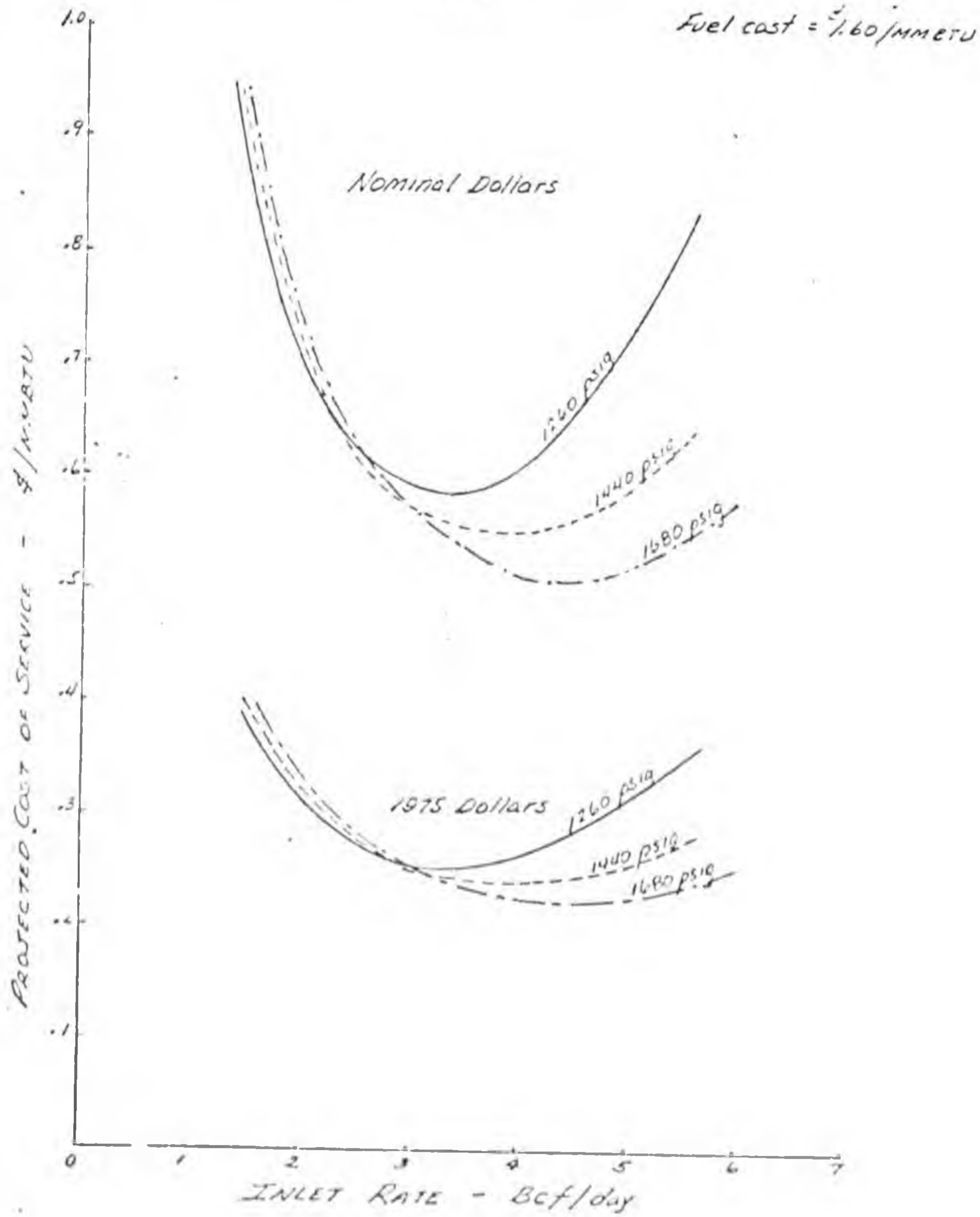
Fuel cost = $1.60/MMBTU
Nominal Dollars
1260 psig
1440 psig
1680 psig
1975 Dollars
1260 psig
1440 psig
1680 psig
PROJECTED COST OF SERVICE - $/MMBTU
INLET RATE - Bcf/day
1.0
.9
.8
.7
.6
.5
.4
.3
.2
.1
0
1
2
3
4
5
6
7

TABLE 1

PROJECTED COST OF SERVICE,

$/MMBTU

Fuel Cost, $/MMBtu		$1.00			$1.60			$2.62	
Pressure, psig	1260	1440	1680	1260	1440	1680	1260	1440	1680
PRUDHOE BAY TO ALASKA-CANADIAN BORDER (Including only the additional processing and conditioning costs required at lower-pressure)									
(1) Nominal Dollars									
Throughput, bcfd									
1.6	.792	.818	.844	.825	.849	.874	.881	.902	.924
2.4	.590	.591	.611	.631	.627	.646	.700	.689	.705
3.2	.531	.515	.510	.589	.563	.552	.687	.645	.623
4.0	.530	.491	.462	.610	.554	.514	.746	.662	.602
4.8	.593	.497	.449	.703	.580	.513	.891	.721	.621
5.6	.693	.544	.474	.843	.650	.553	1.097	.830	.687
(2) 1975 Dollars									
Throughput, bcfd									
1.6	.354	.367	.379	.367	.379	.390	.384	.395	.410
2.4	.262	.263	.273	.278	.277	.286	.305	.302	.309
3.2	.234	.228	.226	.257	.247	.243	.295	.279	.271
4.0	.232	.216	.203	.263	.240	.224	.316	.282	.259
4.8	.257	.216	.197	.300	.249	.222	.373	.304	.264
5.6	.299	.235	.207	.357	.277	.237	.476	.347	.290
PRUDHOE BAY TO WHITEHORSE, YUKON, CANADA (Including only the additional processing and conditioning costs required at lower pressure)									
(3) Nominal Dollars									
Throughput, bcfd									
1.6	.971	.997	1.014	1.009	1.029	1.065	1.071	1.085	1.118
2.4	.726	.727	.741	.774	.768	.779	.855	.838	.842
3.2	.637	.634	.625	.696	.691	.672	.797	.787	.751
4.0	.681	.620	.573	.782	.700	.635	.953	.814	.740
4.8	.765	.659	.567	.910	.767	.644	1.157	.952	.777
5.6	.909	.708	.615	1.109	.847	.716	1.448	1.083	.888
(4) 1975 Dollars									
Throughput, bcfd									
1.6	.436	.449	.465	.451	.460	.477	.475	.482	.498
2.4	.321	.325	.312	.342	.341	.346	.374	.368	.371
3.2	.282	.281	.278	.305	.303	.296	.345	.341	.328
4.0	.298	.273	.253	.337	.304	.277	.404	.356	.318
4.8	.331	.287	.249	.388	.330	.279	.484	.401	.331
5.6	.392	.307	.268	.469	.361	.308	.601	.453	.375

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IV. Alaska Gas Project Office Analysis of Alternative Systems

The staff of the Alaska Gas Project Office prepared independent estimates of the capital costs and cost-of-service for the higher pressure systems for comparison with those submitted by Alaskan Northwest. Our results are plotted in figure 1 for a fuel cost of $1.60 (1975 dollars) per million British thermal units (mmBtu). Table 1 presents cost-of-service calculations for fuel prices of $1.00, $1.60 and $2.62 per mmBtu. The computed costs-of-service reflect the different heating values of the gas mixtures which would be transported at the different operating pressures.[29]

As can be seen on figure 1, higher throughput volumes favor one of the higher pressure alternatives. Likewise, table 1 shows that higher fuel costs reduce the threshold throughput rates at which the higher pressure systems have lower costs-of-service than the lower pressure alternatives.

Our method for preparing the capital cost estimates on which the cost-of-service estimates are based was to start with Alaskan Northwest's March 1977 estimates and adjust those estimates for the cost items which would change as a result of utilizing heavier pipe and higher operating pressures. This is essentially the same method utilized by Alaskan Northwest in preparing its capital cost estimates for the alternative systems. The explanatory material at the end of this section presents our capital cost estimates along with a discussion of how they were determined.

Table 2 presents a comparison of our constant-dollar capital cost estimates (excluding compression) for the 1260-psig and 1680-psig systems with Alaskan Northwest's.[30] As the table indicates, the largest difference in the constant dollar capital cost estimates for the 1680-psig system is only about 2 percent of the total estimate. Thus, the two sets of capital cost estimates must be considered very close.

Figure 2 is a plot of the cost-of-service for the 1260–psig and 1680–psig systems utilizing Alaskan Northwest's capital cost estimates, rather than ours. For a fuel cost of $1.60 per mmBtu, us of their capital cost estimates moves the nominal-dollar threshold for crossing over from the 1260 psig to the 1680 psig as the least cost system to 2.9 bcfd from our 2.65 bcfd. In constant dollars, the respective crossover points are closer, both being just under 3.0 bcfd.

Alaskan Northwest has expressed considerable concern over the possibility of delay inherent in a decision to utilize a higher pressure system. Alaskan Northwest has stated that a decision to utilize a higher pressure system would likely result in a delay of 2 years, resulting in an increase in nominal dollar capital costs of at least $1 billion.

U.S. Government technical experts considered this problem when the Canadian Government solicited our comments as input to its decision on pipe size for the Whitehorse-to-James River segment. At that time our experts concluded that some delay for requisite safety and reliability testing was possible, but could likely be avoided. Their conclusion was:

> We are in agreement that testing all three, or even two, pipe designs will delay completion of construction, perhaps for as long as the two years which the Canadians have predicted. Selection of any one of the size and pressure combinations to the exclusion of all others now or within the near future will permit the pipeline applicants to conduct burst test verification and initiate purchase of the pipe earlier in order to complete the pipeline within the time frame described in the U.S./Canadian agreement.[31]

That report went on to say that, although our experts believe that a confirmatory testing program could be designed for the higher pressure alternative which would have very little likelihood of failure, there was more risk of failure for a higher pressure alternative than for a lower pressure one. Specifically, the experts said:

> We recognize that the possibility of delays associated with testing of the 48-inch 1680 psig pipe may be slightly greater because of the higher pressure.[32]

The impact of delay, as well as the impact of a possibly higher tendency toward cost overrun for the higher pressure systems, is illustrated in figure 3. For a nominal dollar case, we have plotted the cost-of-service for a 1680-psig system with capital costs $1 billion higher than anticipated.[33]

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[29] The assumed heating value of the gas stream for these calculations was 1135 Btu/cubic foot at 1260 psig, 1140 Btu/cubic foot at 1440 psig, and 1154 Btu/cubic foot at 1680 psig. These values differ from those subsequently arrived at in the Parsons study, and would tend to make our cost of service calculations lower than they would be if we had used heating values closer to Parsons'.

The comparisons shown on Figures 1, 2 and 3 in Tables 1, 2 and 3 include differences in gas conditioning plant costs for different pressure systems. Including such differences provides a more precise economic comparison of the various systems. The comparisons shown, however, may not represent true cost differences from the point of view of consumers since the cost of gas conditioning may be borne by the gas producers rather than the consumers. (See the Commission's Notice of Proposed Rulemaking in RM79-19, February 2, 1979.) However, as shown in Table 3, such differences in estimated gas conditioning costs resulting from a change in pressure represent only a very small portion of total costs. The effect of eliminating gas conditioning cost differences would be to move the curves slightly closer together, but would not change any conclusions resulting from analysis of Figures 1, 2 and 3 Tables 1, 2 and 3.

[30] As shown in table 2, we have reallocated some capital costs for the 1260 psig system among the cost categories, although our total capital costs are the same except for the extra costs of processing and conditioning. We have discussed this reallocation with Alaskan Northwest and they do not object.

[31] "U.S. Government Safety and Reliability Evaluation of Different Pipe Size and Pressure Combinations for Alaska Gas Pipeline," *Op. Cit.*, Executive Summary, pp. 1-2.

[32] *Ibid.*, p. 5. In comments on the draft of this report, DOT added, "Realistically, the only 'failure' that could occur relates to the effectiveness of pipe toughness alone to stop ductile fractures. The alternative simply is to add mechanical crack arrestors or rerun the tests with tougher pipe. The latter may mean a 3–6 month delay at worst." (October 20, 1978, Comments, p.

[33] The choice of $1 billion as additional capital cost due to either delay or cost overrun is purely illustrative. Use of this example is not meant to imply that choice of the 1680 psig system would result in a $1 billion cost overrun. We do not now know whether choice of the 1680 psig system would result in any greater cost overruns than for the 1260 psig system.

TABLE [illegible]

COMPARISON OF PIPELINE COST ESTIMATES
1975 Base Costs - $ Millions

	1260 PSIG		1680 PSIG		Difference	
	NAP	FERC	NAP	FERC	NAP	FERC
Changeable Costs						
Pipe cost - delivered	529.1	475.4	704.1	650.4	175.0	175.0
Welding	21.5	25.4	41.6	36.1	20.1	10.7
Double Jointing	14.1	9.7	26.9	13.7	12.8	4.0
Weights	25.1	25.1	18.8	18.8	-6.3	-6.3
VFF, Installed	24.7	24.7	39.4	34.6	14.7	9.9
Bending	4.8	4.8	6.5	6.5	1.7	1.7
Short tie-ins	3.[illegible]	3.9	5.4	5.4	1.5	1.5
Tie-ins	9.5	9.5	18.5	14.2	9.0	4.7
Set Up and Alignment	20.3	20.3	28.0	28.0	7.7	7.7
Special Construction	7.3	7.3	9.6	9.6	2.3	2.3
Crack Arrestors	0	0	12.7	12.7	12.7	12.7
Add'l Side booms, labor	—	—	37.5	10.0	37.5	10.0
Add'l fuel	—	—	5.7	2.0	5.7	2.0
Add'l testing	—	—	10.0	10.0	10.0	10.0
River Crossings	13.0	—*	17.3	—*	4.3	0
	673.3	606.1	982.0	852.0	308.7	245.9
Add'l Prudhoe Bay Processing	0	30.0	0	0	0	-30.0
Other Costs (non-variable)**	991.2	1180.7	991.2	1180.7	0	0
E & S Contingency	183.3	60.6**	193.0	85.2***	9.7	24.6
Total Pipeline Capital Costs (excluding compression)	1847.8	1877.4	2166.2	2117.9	318.4	240.5

* No change in cost assumed - included in other costs

** Derived from subtracting changeable costs from total.

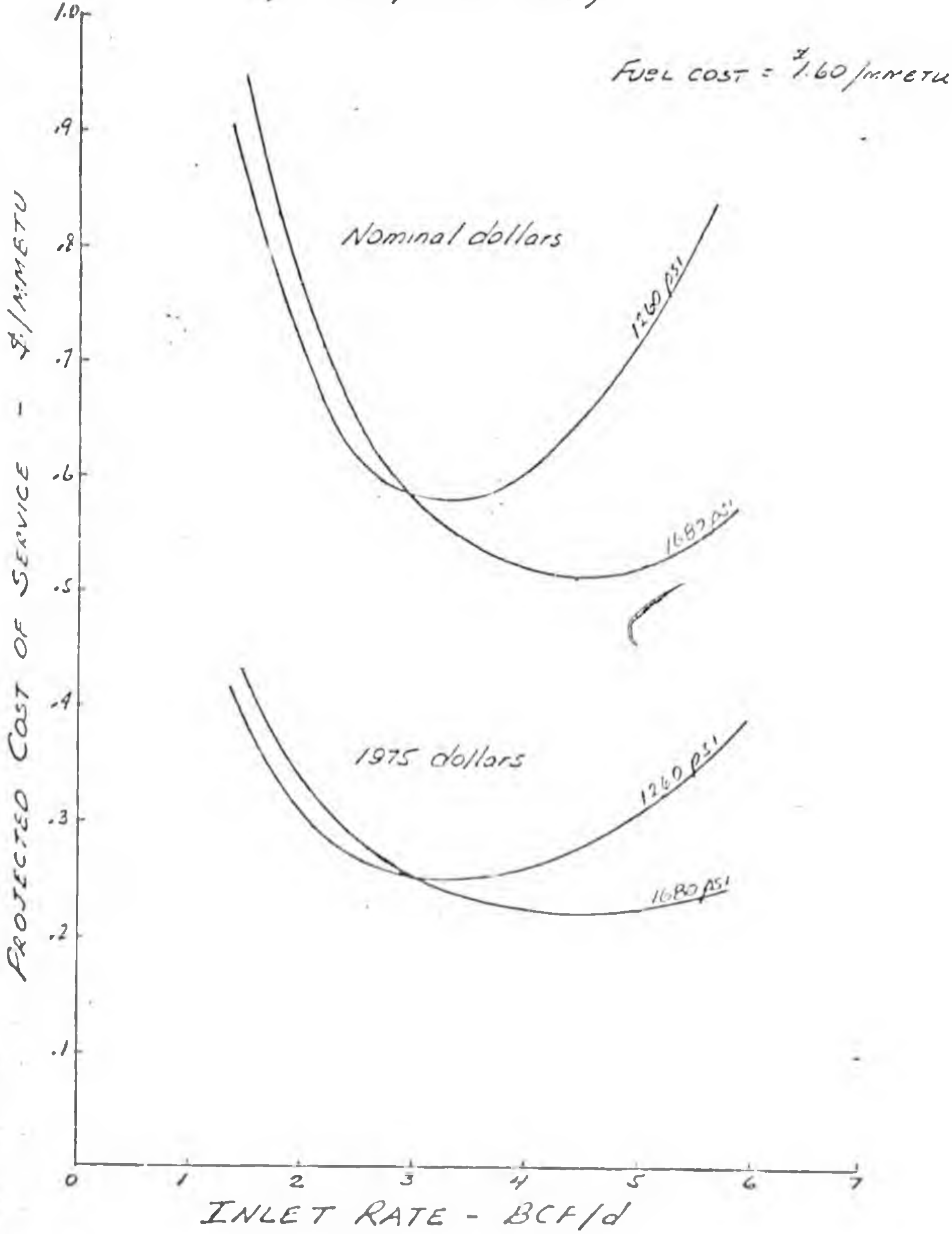
*** Amount on changeable cost items only - add'l amounts included in other costs.

FIGURE 2

-29-

COST OF SERVICE - ALASKA

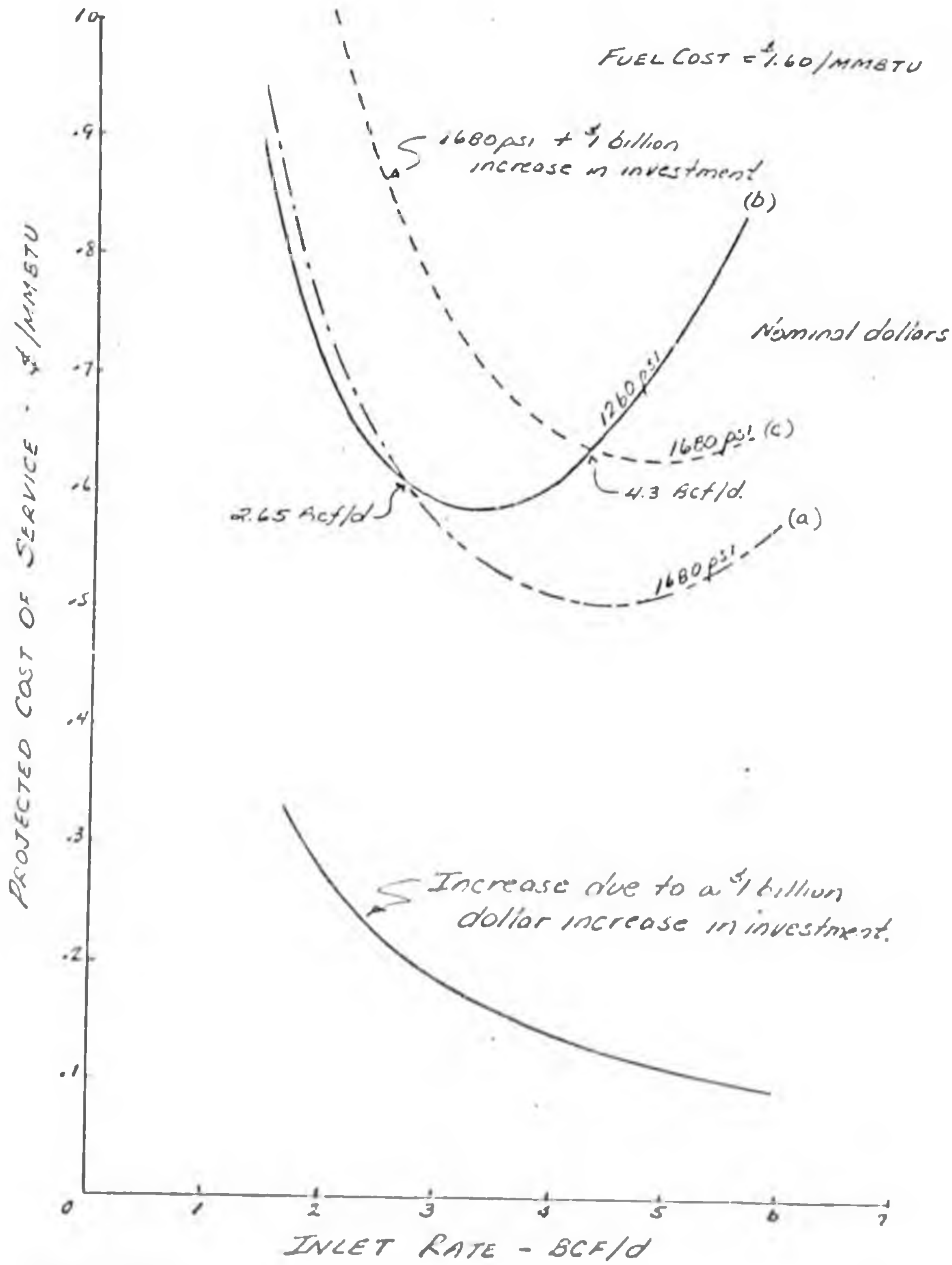
(Utilizing applicant's cost data except for compressor costs)



-31-

FIGURE 3

IMPACT OF AN INCREASE IN INVESTMENT UPON THE COST OF SERVICE



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As can be seen from figure 3, increased capital costs for the high-pressure systems relative to the low-pressure ones, whether due to time delays for testing or relatively higher cost overruns, would have the effect of moving upward the crossover point in throughput volume for going from the lower pressure system to a higher pressure one as the least-cost system. Our calculations show that the spread in unit cost of service, (constant 1975 dollars, fuel cost $1.60 per mmBtu) among the three systems amounts to less than 10 percent of the lowest one for throughput volumes up to about 3.5 bcfd. At higher throughput volumes, the cost of service plots for the three systems start to diverge more rapidly. Alaskan Northwest would put the throughput point at which the cost-of-service plots start to diverge closer to 4.0 bcfd.

The comparison of cost of service plots using our capital cost estimates with those using Alaskan Northwest's illustrates that small differences in assumptions or expectations about capital costs or other parameters can shift the crossover points noticeably.[34] Thus, I conclude that the precise crossover points are less significant for decisionmaking than the points where the cost-of-service plots start to diverge.

Our cost-of-service plot for the 1260-psig system includes the effect of the additional cost of the conditioning facilities to meet the pipeline quality specification at that pressure. This assumption provides an indication of the total system—pipeline plus conditioning facility—cost consequences of the 1260-psig decision. This difference partially explains the difference between our results and Alaskan Northwest's. Other likely sources of difference include:

Heating value of gas streams;

Computation of fuel use for compression and chilling; and

Our simplified cost of service computation methodology.

Explanation of Cost Differences for Various Size Systems

Table A-1 presents estimated investment cost for systems designed to operate at 1260, 1440 and 1680 psig.

Table A-2 summarizes the horsepower (hp) and fuel requirements for the three systems.

Methodology. Total capital costs for the 1260 psig base case system at a 2.4 bcfd throughput rate were taken from the capital cost data filed with the FPC by Alcan Pipeline Company in March 1977. Independent cost estimates were made for all items where costs should change materially as a result of utilizing heavier pipe with a greater wall thickness. These cost estimates are shown in table A-1. The estimated costs of all other (nonvariable) items were assumed to be equal to the difference between filed costs and the total cost of the variable items for the 1260 psig, 2.4 bcfd base case.

Compressor and fuel costs were calculated based upon computed requirements for the three systems for flow rates of 1.6, 2.4, 3.2, 4.0, 4.8 and 5.6 bcfd. An FERC computer model based upon American Gas Association (AGA) pipeline flow equations was used to determine compression and chilling hp and fuel requirements. The additional gas processing and conditioning plant costs relative to those for the 1680-psig system were added to the capital costs of the 1260-psig and 1440-psig systems as that difference could have been reflected in an increment to any gathering and conditioning allowance, if allowed by the Commission. Plant cost differences are based on cost differences included in the materials supplied by Arco, adjusted to 1975 dollars. All other capital costs are expressed in 1975 dollars.

As a result of the above methodology, total costs shown are expected to be only roughly correct. However, cost differences should be reasonably accurate.

Capital cost data from table A-1 and fuel requirements shown in table A-2 were used in an FERC cost of service model to compute an expected cost-of-service for each case. As noted above, cost-of-service differences should be more meaningful than cost-of-service values for individual cases.

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[34] A difference of $77.9 million in relative capital costs, which amounts to 4.2 percent of Alaskan Northwest's estimate for the 1260 psig system and a similar proportion of the estimates for other systems, shifted the crossover point from 2.65 to 2.0 bcfd in the example given above.

TABLE A 1

PIPELINE CAPITAL COST ESTIMATES - FERC

All Costs in Millions of 1975 Dollars

1. Pipeline

		To Canadian Border			To Whitehorse, Yukon		
Pressure	PSIG	1260	1440	1680	1260	1440	1680
Length	Miles	731.4	731.4	731.4	1000	1000	1000
Weight of Pipe	M Tons	646	738	860	859	982	1145
Pipe Cost (Delivered)	MM $	475.4	550.3	650.4	640.9	741.9	876.5
Welding	MM $	25.4	30.1	36.1	34.7	41.0	49.0
Double Jointing	"	9.7	11.3	13.7	12.1	14.2	17.2
Weights	"	25.1	22.0	18.8	36.1	31.6	27.1
Valves, Fittings, Installation	"	24.7	29.6	34.6	33.7	40.5	47.1
Short tie-ins	"	3.9	4.6	5.4	5.3	6.3	7.4
Tie-ins	"	9.5	11.4	14.2	13.0	15.6	19.4
Set Up & Alignment	"	20.3	23.8	28.0	27.8	32.3	38.3
Special Construction	"	7.3	8.4	9.6	10.0	11.5	13.1
Bending	"	4.8	5.5	6.5	6.6	7.5	8.9
Crack Arrestors	"	0	12.7	12.7	0	17.4	17.4
Add'l Sidebooms, labor	"	0	5.0	10.0	0	6.8	13.7
Add'l Fuel	"	0	1.0	2.0	0	1.3	2.6
Test Programs-add'l	"	0	10.0	10.0	0	10.0	10.0
Subtotal		130.7	175.2	201.6	179.3	236.0	271.4
Add'l Contingencies, Engineering & Supervision	"	60.0	72.6	85.2	82.0	97.8	114.8
Subtotal-Variable Items	"	666.7	798.1	937.2	902.2	1075.7	1262.7
Other Costs		1190.7	1180.7	1180.7	1393.2	1393.2	1393.2
Subtotal-	MM $	1847.4*	1978.8	2117.9	2295.4**	2468.9	2655.9
Difference		--	131.4	270.5	--	173.5	360.5
North Slope Costs (Ex Compression) Processing Plant Additions	MM $	30.0	20.0	0	30	20	0
Subtotal (Ex Compression)	MM $	1877.4	1998.8	2117.9	2325.4	2486.9	2655.9

* From Alcan March 1977 filing (Total Cost - AFUDC - Compressor Costs)

** 49.5 percent of Foothills filed costed for the Yukon, minus compressor costs, plus Alaskan costs

TABLE A-1 (Continued)

PIPELINE CAPITAL COST ESTIMATES - VARIOUS SYSTEMS & THROUGHPUT RATES

2. Compression and Cooling

		Alaska			To Whitehorse, Yukon		
	PSIG	1260	1440	1680	1260	1440	1680
Compression & Cooling, Prudhoe Bay Inlet	1.6	16.0	24.0	24.0	16.0	24.0	24.0
	2.4	24.0	32.0	48.0	24.0	32.0	48.0
	3.2	48.0	72.0	80.0	48.0	72.0	80.0
	4.0	72.0	96.0	120.0	72.0	96.0	120.0
	4.8	96.0	120.0	152.0	96.0	120.0	152.0
	5.6	112.0	144.0	192.0	112.0	144.0	192.0
Compression & Cooling, Compressor Stations	1.6	80.0	60.0	40.0	120.0	80.0	60.0
	2.4	180.0	120.0	100.0	240.0	180.0	120.0
	3.2	354.0	260.0	189.0	472.0	354.0	260.0
	4.0	607.0	449.0	283.0	884.0	647.0	410.0
	4.8	1120.0	682.0	475.0	1467.0	1096.0	693.0
	5.6	1815.0	1155.0	840.0	2388.0	1581.0	1235.0
Engineering, Supervision and contingencies for compressor stations.	1.6	9.6	8.4	6.4	13.6	10.4	8.4
	2.4	20.4	15.2	14.8	26.4	21.2	16.8
	3.2	40.2	33.2	26.9	52.0	42.6	34.0
	4.0	68.1	54.5	40.3	95.6	74.3	53.0
	4.8	116.2	80.2	62.7	156.3	121.6	84.5
	5.6	192.7	129.9	103.2	250.0	172.0	142.7
Add Pipeline Cost (Less compression and AFUDC)		1877.4	1998.8	2117.9	2325.4	2488.9	2655.9

3. Total Direct Capital Cost

(Less AFUDC but including Prudhoe Bay extra Processing & Compression)	1.6	1983.0	2091.2	2188.3	2475.0	2603.3	2748.3
	2.4	2101.8	2166.0	2280.7	2615.8	272[illegible]	2840.7
	3.2	2319.6	2364.0	2413.8	2897.4	2957.5	3029.9
	4.0	2624.5	2598.3	2561.2	3377.0	3306.2	3238.9
	4.8	3209.6	2881.0	2807.6	4044.7	3826.5	3585.4
	5.6	3997.1	3427.6	3253.1	5075.4	4386.4	4225.6

Table A-2
Calculated Power and Fuel Requirements
at Different Operating Pressures and Throughput Rates

Operating Pressure, psig	1260			1440			1680		
Throughput rate, bcfd	Compression	Chilling	Total	Compression	Chilling	Total	Compression	Chilling	Total
1. Prudhoe Bay Inlet									
			Summer power requirements (in thousands of HP)						
1.6	64	18	81*	74	22	96	86	27	113
2.4	95	26	122	115	33	148	130	41	170
3.2	127	35	162	149	44	193	173	54	227
4.0	159	44	203	186	55	241	216	68	284
4.8	191	53	244	223	66	289	259	81	340
5.6	222	61	283	260	77	337	303	95	397
			Average (summer and winter) Fuel requirements (in mmcfd)						
1.6			17.0			19.1			21.5
2.4			22.4			26.8			30.8
3.2			29.4			35.0			41.2
4.0			36.8			43.7			51.5
4.8			44.3			52.4			61.7
5.6			51.3			61.1			72.0
2. Prudhoe Bay to Canadian Border									
			Summer power requirements (in thousands of HP)						
1.6	51	21	72	37	16	53	25	11	37
2.4	155	49	204	109	37	146	78	30	108
3.2	350	97	447	246	72	318	169	52	221
4.0	675	178	853	476	129	605	324	90	415
4.8	1156	297	1456	819	214	1033	[illegible]	147	704
5.6	1832	464	2296	1303	334	1637	842	227	1110
			Average (summer and winter) Fuel requirements (in mmcfd)						
1.6			16.6			12.6			8.9
2.4			39.5			28.4			22.1
3.2			86.1			61.8			43.8
4.0			160.9			114.9			79.5
4.8			276.8			193.1			128.4
5.6			444.6			299.0			201.2
3. Prudhoe Bay to Whitehorse									
			Summer power requirements (in thousands of HP)						
1.6	70	19	89	51	14	65	35	9	44
2.4	214	49	263	154	32	187	106	29	135
3.2	667	96	593	351	69	420	237	50	287
4.0	988	177	1165	703	125	828	471	85	557
4.8	1716	293	2008	1218	207	1444	821	145	966
5.6	2681	462	3143	1956	332	2287	1336	224	1560
			Average (summer and winter) Fuel requirements (in mmcfd)						
1.6			20.0			14.4			10.0
2.4			50.2			35.6			24.0
3.2			109.4			78.2			54.5
4.0			202.7			151.8			103.1
4.8			319.6*			261.6			169.5
5.6			591.0			402.5			273.7

* Totals may not equal sum of parts due to rounding.

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Alaska Gas Project Office Capital Cost Estimates

Items for Which Differences in Pipe Weight and Operating Pressure Result in Minimal Differences in Cost

The following activities during pipeline construction were assumed to have the same cost (or only minor cost differences) regardless of the pipe's weight or pressure rating:

1. Right-of-way procurement.
2. Clearing and grading.
3. Workpad and access roads.
4. Ditching.
5. Pipe alignment.
6. Field storage of pipe and materials.
7. Coat and wrap pipe.
8. Pipe inspection.
9. Padding and backfill.
10. Cleanup.
11. Resod.
12. Metering equipment.
13. Automation and telecommunications.
14. River crossings.

In actual practice, increasing the operating pressure should result in only minor differences in actual engineering and supervision costs. However, since these items are frequently considered as add-on items and are usually expressed as a percentage of other items, they were treated as a variable cost in this report.

Items Where Differences in Pipe Weight and Operating Pressure Will Change Costs

Pipe Costs. Pipe costs were computed assuming a 1975 base mill price of $550 per ton for 0.6-inch wall thickness, internally coated pipe, plus the following charges:

1. $10/ton additional cost for 0.686-inch wall thickness pipe.
2. $20/ton additional cost for 0.80-inch wall thickness pipe.
3. $50/ton additional cost for increased pipe toughness.
4. $30/ton increased mill cost-Canadian pipe.
5. $20/ton Yukon tax.

To compute tonnage requirements for pipe it was assumed that the heavier wall thickness required in Class II and III construction locations would increase requirements by 10 percent compared to the tonnage required if the entire line was considered no Class I construction.

Pipe Transportation. It was assumed that the pipe would be shipped from the mill to delivery points in Alaska by intercoastal vessels. The following delivery costs were assumed.

Dollar per ton (1975)

Houston, Texas, to Anchorage, Alaska	60
Houston, Texas, to Prudhoe Bay, Alaska	140
Welland, Ontario, to Skagway, Alaska	100

Pipe delivered to Anchorage (or Seward), Alaska, that will be further shipped to Fairbanks, Alaska, via the Alaska railroad, was assumed to incure an additional charge of $20 per ton. Rail charges from Skagway, Alaska, to Whitehorse, Yukon, were assumed to be $10 per ton.

It was assumed that the pipe would be strung from pipe storage points in Prudhoe Bay, Fairbanks, Anchorage (or Valdez), Alaska, and Whitehorse, Yukon. The following pipe stringing costs were assumed:

Stringing Costs, Dollar Per Ton (1975)

	Wall thickness, inches		
	0.6	0.686	0.80
From			
Prudhoe Bay	21.60	19.80	24.30
Fairbanks—North	18.80	17.40	21.20
Fairbanks—East	15.10	14.20	17.00
Anchorage (Valdez)	15.10	14.20	17.00
Whitehorse	15.10	14.20	17.00

Higher costs were assumed north of the Yukon River. Stringing costs varied because of assumed truck weight limitations. For instance, it was assumed that only two double joints of 0.8-inch wall thickness pipe could be delivered per load compared to three double joints of 0.6-inch thickness pipe. The weight limitations assumed are probably conservative.

Welding. Alaskan Northwest has stated that increasing pipe weight and wall thickness reduces construction speed, due to increased welding requirements. They maintain that such reduced construction rate increases costs significantly more than just the increased welding costs, since a slower pace increases the cost of most construction activities. In contrast, others have stated that increasing wall thickness should not slow down construction.

Our knowledge of the welding procedure is that the stringer bead (the initial weld) is made by a stringer bead crew, which for 48-inch diameter pipe would likely consist of four welders. Upon finishing the stringer bead, the stringer bead crew moves forward to the next joint. Immediately following completion of the stringer bead, the hot pass bead is placed by the hot pass crew. Since the hot pass bead is applied at a slightly higher speed than the stringer bead, the hot pass crew usually has no trouble keeping up with the stringer crew. The filler and cap bead are made by separate crews. Normally, a filler and cap crew will stay with a weld until it is finished. Since more weld material must be placed by the filler and cap welders, there may be several filler and cap crews per stringer crew. When thicker wall pipe is welded, it is only necessary to add more filler and cap welders.

According to our understanding of the process, the only welding problem with thicker wall pipe is that 0.8-inch wall thickness pipe would add about 100,000 to 120,000 man-hours of additional welder time compared to that required for 0.6-inch wall thickness pipe. Assuming a 2-year construction period and 1600 man-hours per year per welder, this additional welding would require adding about 38 welders. There should be no changes in nondestructive testing requirements, and only minor increases in inspection and supervisory personnel.

Construction speed is determined by the speed of the stringer crew. Since the time to make the stringer pass is independent of wall thickness, welding speed, expressed as joints per day or miles per day, should not be a function of wall thickness. As a consequence, increasing the wall thickness of the pipe should not materially reduce construction speed.

Welding costs shown in table A-1 assume manual welding; automatic or semi-automatic machines could probably reduce costs and improve weld quality. Welding time is based upon a theoretical arc time assuming deposition of 0.8 pounds of weld material per minute; changing electrodes is allowed for by adding one-third again to the time spent depositing weld material. We then assume that 50 percent of welders' working time is spent on activities other than these two.

Double Jointing. It was assumed that automatic or semi-automatic welding machines would be utilized for doublejointing under controlled, indoor conditions. The principal differences in doublejointing costs for thicker wall pipe compared to thinner pipe would be an increase in machine and operator time.

Bending. It was assumed that bending costs for the 0.8 inch wall thickness pipe would be 10 percent greater than for pipe with 0.6 inch wall thickness, or about $0.75/four increase.

Sidebooms—Support Tractors. It was assumed that the heavier pipe would necessitate heavier lifting equipment, with a resultant increase in fuel and amortization costs. No increase in operating personnel was assumed.

Concrete Weights. March 1977 filed costs were assumed for the base case. Costs for the heavier pipe were computed assuming that total costs for weights would be proportional to the pipeline negative bouyancy without weights.

Valves and Fittings. Block valve costs of $90,000, $96,000 and $105,000 each were assumed for 1260 psig, 1440 psig and 1680 psig valves, respectively. Installed costs of valves and fittings were assumed to be seven times the valve costs. All costs are based upon 1975 prices.

Compression and Cooling. The high-pressure systems will increase compression and cooling requirements at Prudhoe Bay, but will reduce them at pipeline compressor stations. Computed horsepower requirements are shown on table A–2.

Compressors are now used to reinject produced gas. Existing first stage compressors compress the gas from about 550 psig at flow station discharge points to about 1700 psig. These compressors possibly would not need to be duplicated.[35]

V. Estimates of Throughput Volumes

As is apparent from the plots of transportation costs versus throughput volume, expected throughput volume is an important parameter in determining which of the alternative systems is the most cost-effective design. This section reviews the available information for guidance on this point.

1. *Findings in the Initial Decision.* The quantity of gas reserves on the North Slope of Alaska and the deliverability of these reserves was explored in detail during the hearing before FPC Administrative Law Judge Litt in *El Paso Alaska Company, et al.*, Docket No. CP75-96, *et al.* Judge Litt concluded in the *Initial Decision* that, although the uncertainty of reservoir performance and the possible necessity of water injection precluded exact estimates as to the daily deliveries to be expected from the Prudhoe Bay Field, the weight of the evidence supported a finding that 2.0–2.5 bcfd of gas will initially be available from the Prudhoe Bay Field. (*Initial Decision* at 33.) The proven reserves in the Prudhoe Bay Oil Pool support this finding. If one includes additional reserves from the Sadlerochit, Lisburne, and Kuparuk resevoirs, this estimate may be conservative. Judge Litt noted in connection with the Lisburne and Kuparuk reserves that future development of complete disclosure of past drilling would be necessary to establish the producing capabilities of these formations. (*Initital Decision* at 31.)

Judge Litt also found that the evidence suggested that deliveries above the 2.0–2.5 bcfd level might be available from the North Slope region because of reserves other than in the Prudhoe Bay Field. (*Initial Decision* at 33.) However, he found that the evidence regarding such reserves was unclear and made no specific findings as to the volumes of gas which might be delivered from such reserves.

2. *Findings in the FPC Recommendation to the President.* The FPC stated in the *Recommendation to the President:*

"Thus, we conclude that it is reasonable to assume 2.0 to 2.5 Bcfd from Prudhoe Bay Oil Pool within five years after the commencement of oil production. There exists some possibility of increased delivery from the North Slope of perhaps as much as an additional 1.5 Bcfd from NPR-4 (Naval Petroleum Reserve No. 4), ANWR (The Arctic National Wildlife Range), and the Beaufort Sea as well as other reservoirs in or near the Prudhoe Bay Oil Field. Thus, we find the system should be designed to carry initially 2.0–2.5 Bcfd, and be capable of expansion to an additional 1.0-1.5 Bcfd. (p. I–17)

3. *Findings in the Decision.* The report which accompanies the Decision notes that the increase in the nation's supply of natural gas from an Alaskan gas project is estimated to be 0.7 trillion cubic feet (tcf) per year (2.0 bcfd) by 1985. By 1990, a volume greater than 0.9 tcf per year (2.4 bcfd) might be produced, according to the report.

4. *State of Alaska.* The Prudhoe Bay Field is located on lands owned by the State of Alaska. Detailed information on the production potential of that field has been made available to the State in its capacity as royalty owner and conservation authority. At our request, the State's Department of Natural Resources prepared estimates of reserves and deliverability of gas from State lands in the North Slope region based on all information available to them. Those estimates suggest a deliverability range after 1988 of 2.0 to 4.2 bcfd from State lands (including the Prudhoe Bay Field) with the median estimate at 2.8 bcfd.

5. *U.S. Geological Survey.* As part of the July 1, 1977, reports to the President prepared under the terms of the Alaska Natural Gas Transportation Act (ANGTA), the U.S. Geological survey (USGS) compiled estimates of reserv… and deliverability for all North Slop… areas.[36] The USGS discussion cites t… separate analyses of North Slope potential—its own, that of the Poten… Gas Committee of the Colorado Sch… of Mines, and that of the Division of Geological Survey of the State of Alaska—to conclude that there is v… high probability of substantial additional recoverable gas reserves … the North Slope area.

Converting potential reserve estin… into proven reserves dedicated to pipeline transportation is a demand… exercise in expectation. However, u… the USGS figure of 19 tcf of potential reserves outside the Prudhoe Bay geologic structure, in conjunction w… rule of thumb for deliverability (1 b… production for 20 years requires at l… 20 tcf of potential reserves), plus the State's figure for the Prudhoe Bay Fi… itself, these estimates suggest there … 95 percent probability that deliveral… from all North Slope producing area… will be at least 2.5 bcfd if production… from all of those reserves overlaps through some period in the future, a… seems highly likely. There is a small probability of North Slope deliverab… going as high as 7.5 bcfd.

VI. Additional Considerations

Our discussions with interested parties suggested that consideration… other than design costs and estimate… throughput volumes are important t… choice of system operating pressure… This section presents short discussio… of the most important of those considerations as we understand th…

1. *Vulnerability to Cost Overruns.* … project sponsors have expressed the concern that a higher pressure syste… more vulnerable to cost overruns. So… support for their concern can be fou… in the work of Professor Walter Mea… the University of California at Santa Barbara. In a recent study published … the American Enterprise Institute,[37] Professor Mead reported in a chapte… cost overruns (chapter 6) that an econometric analysis of past Defense Department projects "* * * indicated that cost overruns were significantly related to the length of time required … the development program and the ex…

[35] Sohio noted in its comments on our draft report that whether the compressors will need to be duplicated will depend on whether Prudhoe Bay working interest owners agree to release any of these facilities for gas sales service.

Arco also addressed this point in its comments on the draft report. It noted that the Prudhoe Bay owners installed compressors to reinject gas which is produced with crude oil. At the time gas sales commence the volume of gas which will have to be reinjected will be reduced by the volume of gas sales. However, these compressors may still be required for reinjecting a portion of the gas production in order to maintain crude oil production.

[36] *Report of the Working Group on Supply, Demand and Energy Policy Impacts of Alaska…*, Federal Energy Administration, Department of Commerce, Department of the Interior U.S. Geological Survey, Department of Transportati… Department of the Treasury, Energy Research a… Development Administration, July 1, 1977.

[37] *Transporting Natural Gas from the Arctic: Alternative Systems*, Walter J. Mead, with Gea… W. Rogers and Rufus Z. Smith, American Enter… Institute for Public Policy Research, Washingto… D.C., August 1977.

of technological advance involved in the project." (p. 86) The implication is that the closer to known technology a project is, or more specifically, the more like a previously constructed project a succeeding one is, the better the cost estimates for the successor project and the less its tendency to cost overruns. To the extent that the 1260-psig system can be considered closer to known technology than either of the higher pressure alternatives, [illegible] tendency to cost overrun shou[illegible] an analogy to Professor Mead's [illegible] us of Defense Department project[illegible] appropriate.

Any difference in their respective tendencies toward cost overrun between the 1260-psig system and the higher pressure alternatives would have the effect of raising the crossover point where increased throughput volume makes a higher pressure system result in lower unit transportation charges. Figure 3 in the section which presented the results of our calculations (section IV, *supra*) shows the effect on the crossover point of an increase in capital costs for a high-pressure system. A similar effect on the crossover point would be realized if cost overruns had the effect of increasing the costs of a higher pressure system relatively more than those of the 1260-psig alternative.

2. *Impact on Financing.* The *Decision* requires that the Alaskan Natural Gas Transportation System be privately financed. Therefore, the impact of a decision to utilize a higher pressure system on the ability of the sponsors to obtain private financing is a major concern.

The risk of major cost overruns creates whatever risk there is of project non-completion, and presents the largest single financing problem for the project. Thus, if the lower pressure system is clo[illegible], to current gas pipeline industry practices, the analysis referred to by Professor Mead would suggest that utilizing the lower pressure alternative reduces the likelihood of major cost overruns and thereby facilitates financing. The effect of technological advances on the reliability of cost estimates was alluded to by the NEB in its February 10, 1978, "Statement of Position."[38]

In response to our request for more definitive information on the significance of the pressure question for financing, the project sponsors' principal financial advisers prepared a letter explaining the effect of a decision to utilize a higher pressure system on the financing proposals of the pipeline project. The gist of their concern is that a higher pressure system involves technological risks that lenders and potential equity investors simply will not accept.

3. *The Gas Consumers' Interest.* The interest of the gas consumer in the low-pressure/high-pressure decision is not obvious. Although a higher pressure system should result in lower transportation charges at higher levels of throughput, it is not assured that such reductions in transportation cost will accrue directly to the benefit to gas consumers.

The means by which delivered price is set for the gas to be transported by ANGTS does not lead to a clear-cut showing of consumer benefit. For the initial throughput volume, an expected 2.0 bcfd from the Main Pool Reservoir of the Prudhoe Bay Fi[illegible], the deliverd price will be the sum of the transportation charge and a wellhead price, plus an allowance for gathering and conditioning if allowed by the Commission. In this case, reduced transportation charges should be passed on to gas consumers as reductions in delivered prices.

In the next few years, however, high-priced sources of gas such as the Prudhoe Bay gas could rapidly exhaust the implicit subsidies provided by allowing the price of this gas to be averaged in with lower cost gas from conventional supply sources. As soon as the use of "rolled-in" pricing has raised the average price of all gas to approximate parity with the delivered price of alternate fuels, incremental gas sales are likely to be made only at prices set by competition with those of alternative fuels. At that point reductions in transportation charges would likely accrue to producers.[39]

Depending on the relationship of the netback to the field price from the market value of this gas on the one hand, and the maximum lawful ceiling price set by the NGPA on the other, possible Commission use of rolled-in pricing for other gas supply projects, and changes in the delivered prices of competing fuels, prices for North Slope gas sales after the initial 2.0 bcfd from the Main Pool Reservoir could be set by a netback from the delivered prices of competing fuels. In that event, reduced transportation charges for these incremental volumes would benefit the gas producers.

An efficient natural gas transportation system which encourages the development of additional supply through higher field prices is not without some consumer benefit. The point here is that an analysis of that benefit is not as simple as might be implied by a comparative evaluation of transporation cost curves.

4. *Alternative Investment Requirements.* Cooling the oil pipeline to move the butane which cannot be transported by the 1260-psig gas pipeline system appears to require a smaller capital investment than increasing the operating pressure of the gas pipeline. The figures provided by the gas pipeline project sponsors show an increased investment requirement of $237 million (in 1975 dollars) to go to the 1680-psig system. Using the oil pipeline would require (in 1978 dollars): [40]

[In million of dollars]

Increased investment in gas conditioning plant	30
Cooling facilities for oil pipeline	37-70
Total	67-100

Alternatively, if the reduction in gas pipeline pressure results in the use of butane as field fuel and/or disposition by reinjection, the following investments (in 19878 dollars) would be required: [40]

[In millions of dollars]

Increased investment in gas conditioning plant	30
Field fuel system investment	50
Injection investment	25
Total	105

As the likely outcome of decision to use the 1260-psig system would be a

[38] "Until sufficient field welding tests and production trials are done to establish suitable procedures and the manpower and equipment requirements to achieve progress rates compatible with other crews, the National Energy Board feels the present cost comparisons (between standard-pressure and high pressure alternatives) based on normal procedures may not be valid." NEB Statement of Position, *op. cit.*, Technical Review, pp. 3-4.

[39] A limitation on such a potential benefit to producers will be the ceiling price on natural gas produced from Prudhoe Bay Unit established by § 109 of the Natural Gas Policy Act of 1978 (NGPA). The price of competing fuels may only determine the price of gas from the Prudhoe Bay Unit to the extent such a price is equal to or less than the ceiling price.

[40] All of these estimates are my interpretations of certain investment figures supplied by Arco. Arco did not provide any comment on this comparison as it appeared in my draft report.

Sohio pointed out in comments on my draft report that crude oil cooling costs were estimated by the R. M. Parsons Company to be about $55 million in 1978 dollars for the case of maximum volume of butanes (31,200 barrels/day) in the TAPS line, assumed to be operating at 1.5 million barrels/day throughput (maximum cooling required). Sohio also noted that oil cooling costs could be partly offset by the lower investment in sales boost compression facilities required for 1260 psig operation, as compared to 1440 or 1680 psig. Sohio concludes:

"The net differential investment which would be required in the conditioning facilities and in various Prudhoe Bay Field facilities to be compatible with a 1260 psig pipeline system is expected to add considerably less than the $100 million (in 1978 dollars) estimated by Arco, event when all butanes recovered are transported in the TAPS lines in preference to blending them with the sales gas. Operating costs of oil coolers are also expected to be less than those related to additional gas compression." (Sohio comments, October 27, 1978, p. 2) combination of cooling the oil pipeline, use of the extra butane in the field, and reinjection, we believed approximately $100 million (in 1978 dollars), including the $30 million required for additional investment in the processing and conditioning facility, is a representative requirement for comparison with the $237 milllion (in 1975 dollars) additional investment requirement to increase the system operating pressure to 1680 psig. None of these figures consider operating costs, so any comparisons are necessarily incomplete.

The gas consumer would see the increased investment requirement in the form of increased transportation charges for gas delivered by a higher pressure system, at least for the first 2.0 bcfd of throughput. Although the increase in unit transportation charges would be tempered by the delivery of higher Btu gas, the additional Btu's per unit volume would not be enough to offset the higher tranportation charges until throughput volumes get higher than just those from the Main Pool Reservoir of the Prudhoe Bay Field.[41]

On the other hand, the oil consumer would not likely be directly affected by a requirement for additional investment in oil pipeline facilities. North Slope oil prices are effectively set through competition with imported oil, and cannot be increased to consumers in order to recover additional transportation costs. Additional investment in the Trans-Alaska Pipeline System (TAPS) simply reduces the netback to the oil producers at the field. The consumer price impact of using the oil pipeline to carry the butane would only be felt as an increase in any processing and conditioning allowance which might have been allowed by the Commission to cover the $30 million extra investment required for the processing and conditioning plant.

The investment requirement not touched on in the preceding discussion is that which might be required for vapor recovery systems on storage tanks in areas where the higher vapor pressure caused by adding butane to the North Slope crude would cause unacceptable air pollution problems. Such ancillary investment requirements highlight the importance of the gas pipeline system design question for the North Slope gas producers, as well as for the gas pipeline project sponsors, and the degree of interest the producers should have in optimizing the design of all facilities involved in producing and transporting Prudhoe Bay hydrocarbon resources.

VII. Requirements for Resolution

I believe that the *Decision* creates a predisposition that the 1260-psig system is the one authorized by the President and the Congress by its reference to "the facilities * * * included in the revised Alcan filing submitted to the Federal Power Commission (FPC) on March 8, 1977."[42] Additional NGL's carrying capability of a higher pressure system might be a desirable feature, all other things being equal. However, a technical report filed with the State of Alaska by the major interest owners in the Prudhoe Bay Field (Arco, BP, Exxon and Sohio) in support of their proposed reservoir management plan states:

> Gas pipeline specifications are not currently known and final specifications may increase or decrease the volume of liquids which must be extracted from the gas to prevent condensation in the pipeline. Regardless of the final gas conditioning requirements, all liquids extracted will be used without waste, either to displace fuel gas or to be transported through the oil pipeline.[43]

I believe that the language in the Report accompanying the *Decision* suggesting that:

> * * * Alcan should consider increasing the operating pressure and wall thickness of its 48 inch diameter pipeline in order to allow for more efficient increases in throughput rate for additional reserves which might be committed to the system from either Alaska or Canadian sources * * *.[44]

would make the predisposition a rebuttable one on appropriate showings in a final authorization proceeding for these facilities. The discussion below highlights the principal factors which should be evaluated in such proceeding, should one be required to [illegible] this parameter. I believe that favorable findings in all three areas would be required to support a decision to increase the operating pressure of the Alaskan segment.

1. *Concurrence of the Canadian Government.* The Government of Canada, across whose territory some length of any of the 48 inch alternatives would have to pass,[45] has previously expressed severe reservations about the 1680-psig alternative on safety and reliability grounds. The Canadian project sponsors share those reservations. The U.S. project sponsors, while concerned about safety and reliability problems (particularly those associated with proximity to the Alyeska oil pipeline), are primarily concerned that uncertainties associated with the 1680-psig system would create significantly higher risks of construction delay and cost overrun than the 1260-psig alternative.

The hearing record on the safety and reliability aspects of the 1680-psig system was more extensively developed in Canada than in the U.S. proceedings before the FPC. Accordingly, although U.S. technical representatives continue to believe that the 1680-psig system can be constructed and operated safely and reliably,[46] Canadian authorities still have reservations about the high-pressure alternative based on the evidence presented to them.[47]

The U.S. project sponsors have also expressed concern about additional hazards of a higher pressure system because of proximity to the TAPS. The additional potential energy in a higher pressure system is thought to represent more of a threat to the structural integrity of the oil pipeline in the event of a gas pipeline rupture. On the other hand, technical representatives of Exxon, one of the principal owners of TAPS, did not feel there was any significant difference in hazard to the oil pipeline between the 1260-psig and 1680-psig alternatives.

A testing program involving the project sponsors, the owners of the oil pipeline and the Canadian Government

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[41] Future gas volumes made available for shipment could have less NGL's content than the Prudhoe Bay accumulation, in which case the "diner" composite gas stream would have more capacity for Prudhoe Bay NGL's without increasing system operating pressure.

[42] *Decision, op. cit.*, p. 13.

[43] Exhibit ALA-31 filed in proceedings before FPC, p. 10. Cited in *Comments on the Decision and Report to Congress on the Alaska Natural Gas Transportation System*, Federal Energy Regulatory Commission, October, 1977.

[44] *Decision, op. cit.*, p. 103.

[45] On February 17, 1978, the Canadian National Energy Board chose a large diameter (56 inch) alternative for the segment of the system through which both Canadian and U.S. gas volumes will flow, to be installed between Whitehorse, in the Yukon Territory, and the Information point near James River in Alberta. Although the operating pressure of the 56 inch system will be 1080 psig, its NGL's carrying capacity is not less than that of a 1680 psig system installed farther north. The reason is the difference in operating temperature: the 56 inch system will operate at a minimum of 40° F, while the northern portions of the system will have to be chilled to below the freezing point of water (32° F) to avoid thaw settlement problems in permafrost soils.

Permafrost soils, and consequently the need for operating the pipeline at or below 32° F, extend less than 100 miles into Canada. The operating temperature can be increased south of that point, allowing the operating pressure to be gradually lowered without losing significant NGL's carrying capacity. The 1680 psig system is, however, incompatible with the very high pressure (2150 psig) system advocated at one point by Exxon.

Thus, Canada would have to approve the use of a higher pressure system for a short distance from the Alaska/Yukon border if such a system is to be used in Alaska.

[46] "U.S. Government Safety and Reliability Evaluation of Different Pipe Size and Pressure Combinations for Alaska Gas Pipeline", *Op. Cit.*

[47] Their "Statement of Position" has previously been referenced. See page 4.

would seem to be required prior to any decision to increase the operating pressure of the gas pipeline. Exxon representatives in particular have suggested that the required testing program would not be extensive, but we doubt they have tried to convince the Canadian Government or the Canadian projece sponsors, both of whom would have to be satisfied with the testing program and its results before a decision to utilize a higher pressure system could be made.

2. *Satisfactory Distribution of Costs and Benefits.* In the preceding section, I discussed my concern that consumers might not be the primary beneficiaries of a decision to utilize a higher pressure system for the Alaska segment. Here I suggest briefly what types of analysis would be required to support a conclusion that consumers would benefit from higher pressure.

The first consideration is expectations about throughput volumes which would suggest that lower transportation costs are likely with higher pressure. A positive finding in this area would have to involve not only conclusions about ultimate throughput, but also the timing of throughput increases, as a decision to ask consumers to pay more now in order to pay less later would have to pass a present value test.

The North Slope producers either now have or will have the geophysical and drilling information which might support increased capacity in the delivery system. Much of this information may have been supplied by them to the State of Alaska and the USGS, but under confidentiality arrangements which effectively deny access to any parties not specifically granted permission by the producers. I believe that the burden of proof that a higher capacity system is required is on the producers.

A second consideration is the possibility of a differential tendency to cost overrun between the 1260 psig system and the higher pressure alternatives. As discussed in a previous section, such a tendency would displace upward the throughput volume threshold where a higher pressure alternative has a lower unit cost of service than the 1260 psig system. Further studies of the cost overrun problem are currently in progress,[48] and should be available for evaluation in the event that an initial burden of proof regarding volumes available for throughput had been satisfied.

3. *Resolution of Extraordinary Financing Problems.* I believe that requiring the chosen system to be privately financed in an integral part of an elaborate framework set out in the President's *Decision* to ensure that construction of the selected system is in the public interest. I also feel that it would be inappropriate for the Commission to make any decision which would undermine a component of that framework. I believe that a showing that any extraordinary financing problems associated with choosing a higher pressure system had been resolved would be an essential element in any such choice by the Commission.

VIII. Results of Conference

An earlier draft of this report was circulated for comment in late September 1978, to the parties with whom we had discussed this matter. The same draft was sent to all parties in Docket No. CP78–123, *et al.*, during November, 1978.

The comments I received indicated a number of corrections to be made which have been incorporated as appropriate but did not alter my basic assessment of the difficulties involved in reaching a determination to increase the operating pressure from the level which had been approved as part of the President's *Decision.*[49]

An on the record conference of interested parties was held on December 15, 1978. At that conference I presented a proposition, which had been suggested in the comments of the State of Alaska on my draft report, for consideration by the project sponsors and any other interested parties. That proposition was to first construct and operate the pipeline at 1260 psig, and then to increase operating pressure of the pipeline *if* sufficient throughput volumes became available during the operating life of the pipeline to warrant the increase. The State of Alaska suggested that it might be

> * * * possible to achieve operating pressures approaching 1440 psig by relaxation of the "design factor" for the pipe Northwest proposes to use from .72 to .8. See 49 CFR 192.111. This would not be a substantial change because the "relaxation" is only to the established Canadian standard. A waiver request would have to be presented to the Office of Pipeline Safety [Department of Transportation] but a good case would be made that safety concerns would be satisfied by the relaxed design factor based on the record in Canada. (November 17, 1978 Comments, p. 7)

The Department of Transportation (DOT) and its Office of Pipeline Safety were represented at my conference. Their representatives were not encouraging about the prospects for a waiver because of the proximity of the pipeline to the haul road which serves the North Slope producing area. DOT safety requirements are more stringent for gas pipelines which operate near highways:[50] thus, sufficient relaxation of the standard to accommodate an increase in operating pressure would likely require a double waiver. The DOT representatives advised use of thicker-wall pipe if higher operating pressures were to be attempted.

I closed the conference by requesting that the project sponsors present their views on the operating pressure question in detail to the State of Alaska and the DOT, both of whom appeared to favor a higher capacity system.[51] The sponsors were then to report to the Commission on their views regarding the possibility of increasing the system capacity, and on the results of their discussions of this matter with other interested parties. The sponsors' filing of March 2, 1979, requesting a Commission order finalizing the selection of 1260 psig as the operating pressure for the Alaska segment, is in compliance with my request. A copy of that filing is attached to this report.

IX. Conclusions and Recommendations

Relevant Considerations. As discussed in section IV above, the primary method of analysis to determine the appropriate throughput capacity for a gas pipeline is the comparison of plots of unit transportation cost vs. throughput volume for alternative system configurations. The project sponsors have attached such plots for the principal alternative systems as Exhibits Z–4 and Z–5 in their filing. Similar computations are also included in section IV of this report.

In my judgement, there are two factors in these comparisons which should be considered:

The least cost system at expected levels of throughput, and

Expectations about the throughput levels for which fuel penalties start to

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[48] For example, the Rand Corporation has been studying this problem applied to coal gasification plants for the Department of Energy.

[49] The U.S. Department of Transportation expressed some concern over perverse incentives inherent in the way natural gas pipeline projects are regulated. I took note of their concerns but advised them that the Commission would likely be unable to resolve them.

[50] Whether the haul road is properly classified as a "highway", and thus imposes the more stringent safety standard on the gas pipeline, is a matter which I believe is still at issue.

[51] Arco representatives, both in their comments on my draft report and in their remarks at my conference, favored increasing the operating pressure but reducing the diameter of the gas pipeline system. Exhibit Z–5, attached to the project sponsors' March 2, 1979 filing, indicates that the operating efficiency characteristics of the 1440 psig, 42 inch system which Arco favors are essentially the same as those for a 1260 psig, 48 inch system.

significantly increase the unit transportation cost.

For expected levels of throughput up to 3.3 bcfd, the 1,260-psig system is indicated by the project sponsors' analysis. Although our analysis puts the crossover point from the 1,260 psig system to the 1,440-psig system slightly lower than the project sponsors',[52] our analysis also supports the 1,260-psig system if the expected levels are in the 2.8- to 2.9-bcfd range.

Perhaps more important, in my judgement, is an assessment of the likelihood that throughput levels will exceed the range of efficient operation for the recommended system. For the three systems which appear to be feasible for the Alaska segment—1,260, 1,440 and 1,680 psig systems—there is a considerable range of throughput volumes for which there is probably sufficient uncertainty the capital cost estimates upon which the cost of service calculations are based to prevent a definitive conclusion that one will have a lower unit cost of service than another. For example, if I arbitrarily pick a difference of 10 percent between the cost of service of the lowest and highest cost systems for a given throughput level as a difference which is significant, then the unit cost of service for all three systems would be essentially the same from a throughput of about 2.6 bcfd to almost 4.0 bcfd, according to Alaskan Northwest's Exhibit Z-4. Above 4.0 bcfd and below 2.6 bcfd, the three curves diverge more rapidly.

Our computations in section IV illustrate better the divergence of the "J-Curves" at higher throughput volumes because we have plotted them for a larger range of throughput. On the next page, I have used the data from my Figure 1 to plot the difference between the lowest and highest cost systems as a percent of the lowest cost system for various levels of throughput. Notice that because of differences in our respective capital cost figures, our 10 percent difference point is closer to 3.5 bcfd than Alaskan Northwest's 4.0 bcfd. However, the plot illustrates that, although the differences are small over a range of throughput, they increase rapidly as the upper end of the range of efficient operation for the 1,260-psig system is approached.

In section VII of this report, I discussed the difficult problems which would have to be resolved to reach a determination to increase the operating pressure of the Alaskan segment. I believe that the Commission need not address these problems unless there is a significant change in expectations about gas volumes available from the producing areas to be served by the ANGTS. In view of the difficulties discussed in my report and in view of the relatively small differences in unit costs of service over the range of at least 2.6 to 3.5 bcfd, I would recommend that you reaffirm the 1,260-psig system for the Alaskan segment unless you are provided with new information which demonstrates that there is a significant probability of volumes in excess of 4.0 bcfd in the area to be served by the ANGTS.

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[52] Our results put the crossover point at 2.65 to 2.8 bcfd, depending on certain assumptions about capital costs other than for compression. The remainder of the difference between our analysis and Alaskan Northwest's is in the installed cost of compression and chilling facilities. I would caution against assigning undue precision to the exact crossover points from one system to another. The differences between Northwest's capital cost estimates and ours for the 1,680 psig system is $30.1 million, or less than 3 percent of the base 1,260 psig estimate, whereas the expected cost overrun for the 1,260 psig case is about 30 percent of that estimate.

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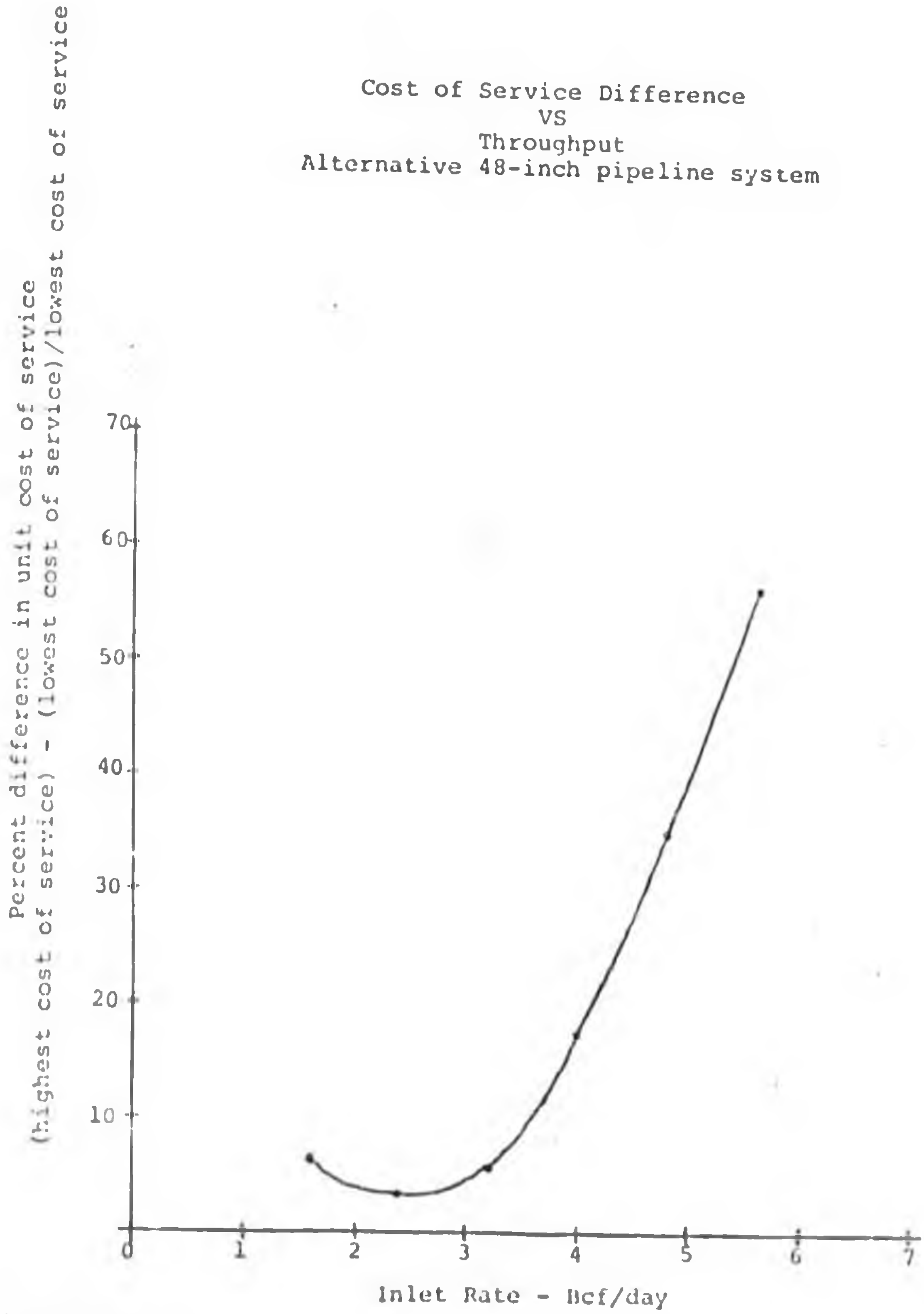

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Status of Information. The information available at the time of the *Decision,* the results of the extensive analysis by the FPC and the July 1, 1977, *Report to the President of the Working Group on Supply, Demand and Energy Policy Impacts of Alaska Gas,* are cited in the project sponsor's filing. They cite the relevant conclusion the the *Decision* as the following:

> Peak-day capacity utilizing nine compressor stations will be 2.6 bcfd, with an average daily volume of 2.4 bcfd. By installation of intermediate compressor stations, the system could be increased to 3.4 bcfd peak capacity, with an average day capacity of 3.2 bcfd. The system capacity could be further increased by addition to the compressor horsepower at each station. (*Decision,* p. 17.)

I also note in the report accompanying the *Decision* the following passage:

> The routing of the Alcan system provides future access to reserves which might be discovered in the Beaufort Sea or elsewhere on the North Slope. Alcan similarly could transport gas from other areas of Alaska or even from the Gulf of Alaska by means or even from the Gulf of Alaska by means of somewhat longer supply laterals. Further, the agreement with Canada provides for the use by Canada of the Alcan main line at a throughout up to 1.2 bcfd. Therefore, redesign of the system to enable inexpensive expansibility up to 3.9 to 4.0 bcfd south of Whitehorse, Yukon Territory, is essential. (*Decision,* p. 106.)

I infer from this passage that the throughout volume anticipated at that time from sources in Alaska which might be connected to the ANGTS was in the range of 2.7 to 2.8 bcfd (3.9 to 4.0 bcfd less 1.2 bcfd).

Interestingly, the principal concern about throughput volume at the time of Congressional consideration of the *Decision* was that Prudhoe Bay Field production might not come up to expectations, and thus the system selected by the President might be too large for the available volumes.[53] Some perspective on the possibility that available volumes will be either higher or lower than expected was provided to us in the course of this inquiry by the State of Alaska. As both a royalty owner and the conservation authority for the primary prospective areas on the North Slope, the State's information on these areas must be presumed to be as complete as anyone's. I have reproduced on the next two pages a series of tables of expected reserves and deliverability, along with a map of the area covered by the estimates. As you can see from the tables, the estimated probability that available throughput volumes will be 4.2 bcfd is about the same as the probability that throughput will be only 2.0 bcfd. I don't see any basis in this information for changing from the 1260 psig system.

The CO_2 Standard. A matter which I feel ought to be considered further is the CO_2 standard for gas delivered to the pipeline. I mentioned above (p. 22) that the Parsons study recommends further study of possible alternative specifications for CO_2 content and gas pipeline pressure. Increasing the system operating pressure is difficult for all the reasons discussed above, but I believe changing the CO_2 specification is separable and should considered. The potential benefits to be derived from transporting more CO_2 include reduced conditioning costs, increased capacity for transporting NGL's, and possibly increased availability of NGL's (particularly propane) due to reduced fuel requirements of a less intensive processing and conditioning plant operation. The State of Alaska and Arco[54] raised the CO_2 issue in comments on the project sponsor's March 2, 1979 filing regarding system operating pressure. Sohio[55] has raised the subject of standards for "pipeline quality gas" in the Commission's omnibus rulemaking proceeding on tariff and rate of return issues in Docket No. RM78-12.

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[53] See the very extensive discussions of this matter during the Senate consideration of the *Decision.* Hearings before the committee on Energy and Natural Resources, United States Senate, on S.J. Res. 82, Joint Resolution to Approve the Presidential Decision on an Alaska Natural Gas Transportation System, September 26, 27, October 11, 12 and 25, 1977, Publication No. 95-73.

[54] "Comments of the State of Alaska on the Design Specifications and Initial System Capacity of the Alaskan Segment of the Alaska Highway Pipeline Project", and "Motion of Atlantic Richfield Company for Clarification," both filed in Alaska Northwest Natural Transportation Company, Docket No. CP78-123 *et al.* on April 5, 1979.

[55] "Comments of Sohio Natural Resources Company on Notice of Proposed Rulemaking Issued April 6, 1978", filed in Determination of Incentive Rate of Return, Tariff and Related Issues, Docket No. RM78-12, on May 7, 1979.

North Slope
Original Gas In Place
Trillion Cubic Feet

	Confidence Level 95	50	5
Prudhoe Bay	←	40.4	→
All Other	0.5	13.4	30.5

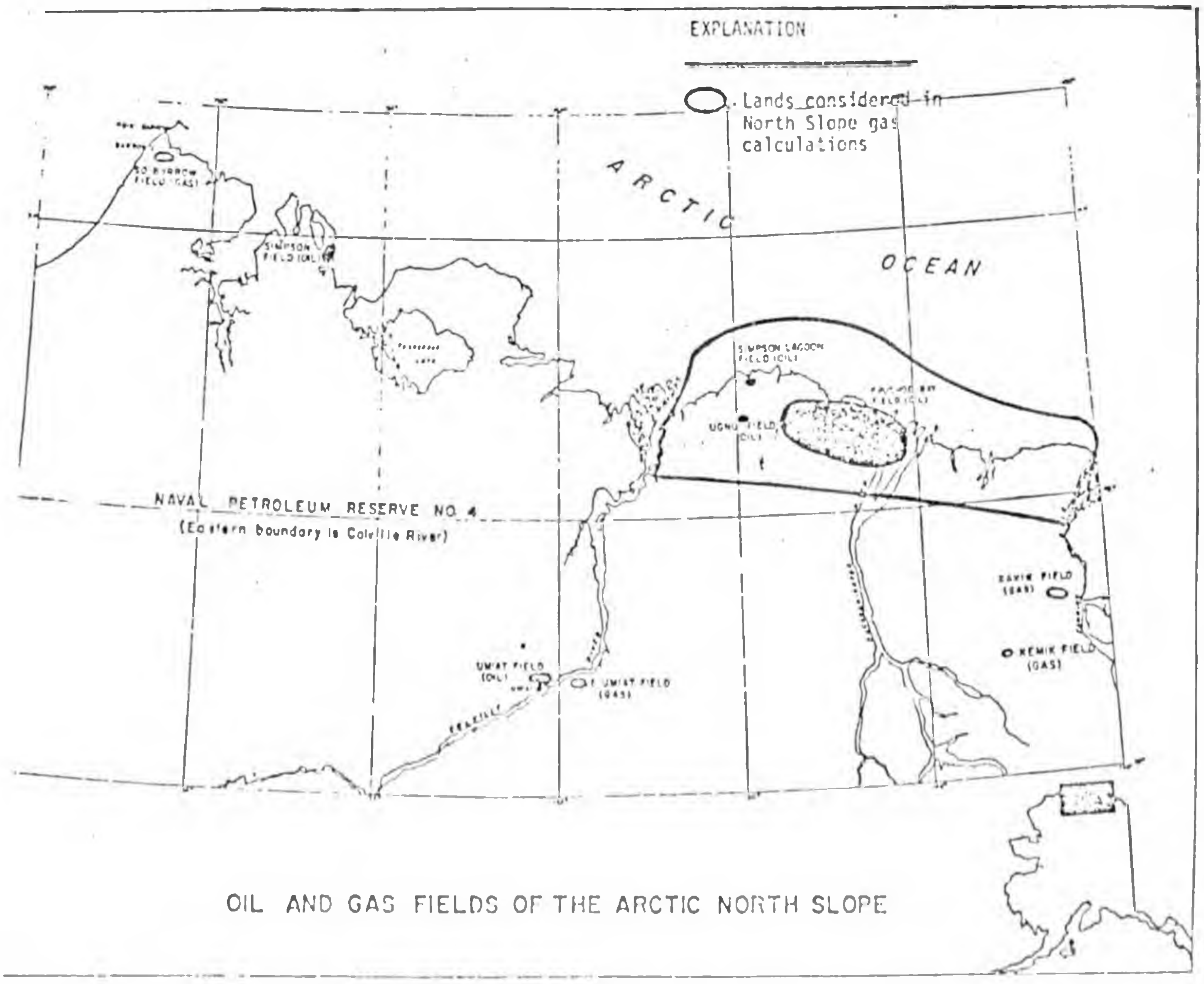
Recoverable Reserves *
Trillion Cubic Feet

	Confidence Level 95	50	5
Prudhoe Bay	←	21.0	→
All Other	0.3	8.0	18.3

Deliverability
Billion Cubic Feet Per Day

	Confidence Level 95	50	5
Mid 1984			
Prudhoe Bay	1.5	2.0	2.5
All Other	0	0.3	0.5
Mid 1988 and Beyond			
Prudhoe Bay	1.5	2.0	2.5
All Other	0.5	0.8	1.7

* takes into account recovery factor, gas conditioning and fuel useage.

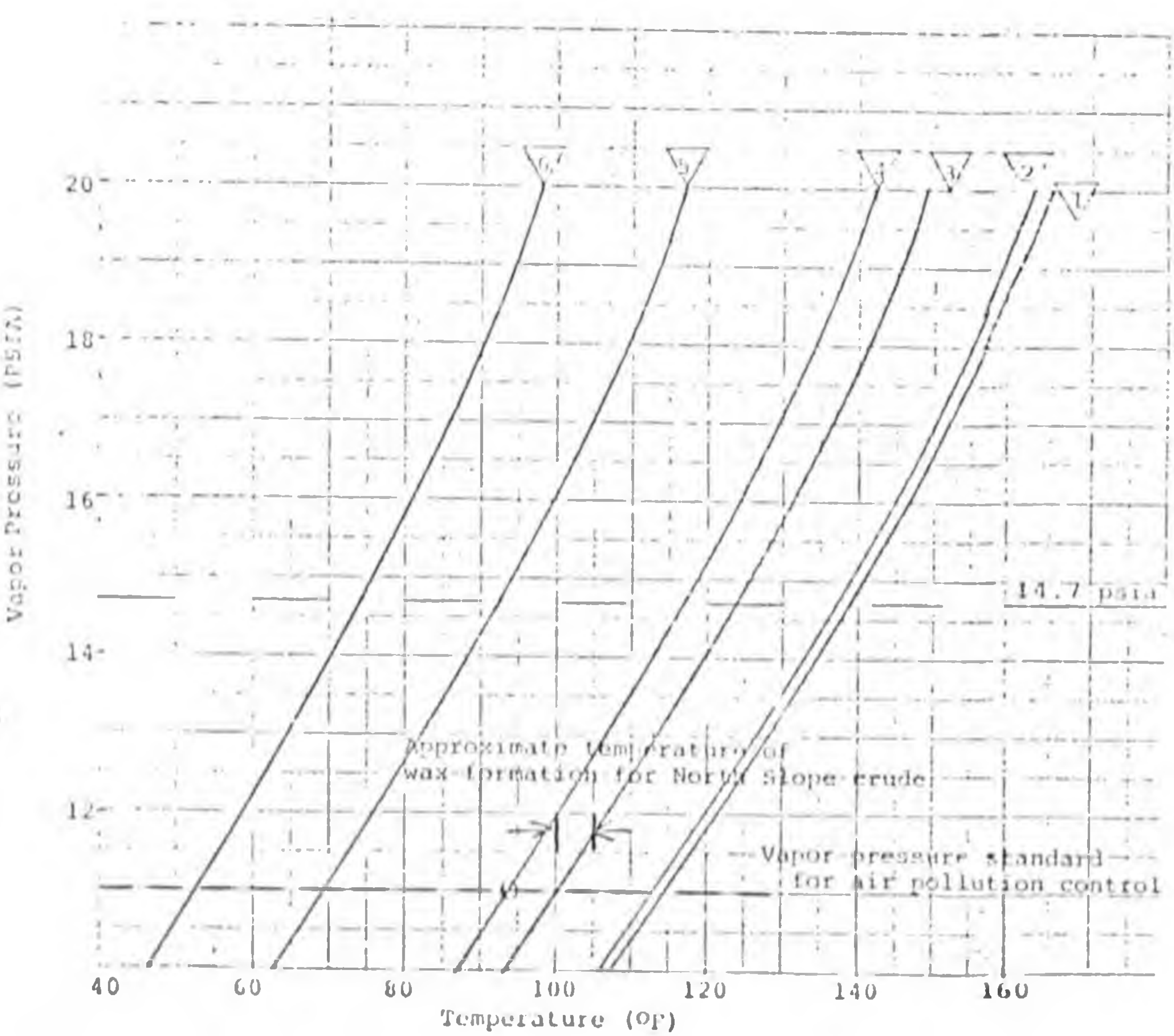


OIL AND GAS FIELDS OF THE ARCTIC NORTH SLOPE

FIGURE 1 -65-

PRUDHOE BAY CRUDE + NGL VAPOR PRESSURE

Bbl.NGL/Bbl.Crude		Mixture
0	1	Crude
.0154	2	Crude + iC5+
.0301	3	Crude + NC4+
.0367	4	Crude + iC4+
.0470	5	Crude + 25% C3, iC4+
.0573	6	Crude + 50% C3, iC4+



The North Slope producers and the State of Alaska have an additional interest in this matter because of the impact of butane blending on the vapor pressure of North Slope crude. Exxon had furnished the plot of vapor pressures verses temperature for North Slope crude containing various amounts of NGL's which appears on the following page. I have super-imposed on that plot the approximate temperature range at which wax formation starts to be problem with the North Slope crude, and the vapor pressure standard for air pollution control in Southern California.

Wax formation limits the use of cooling as a technique for vapor pressure control. If cooling cannot be used, then vapor recovery systems must be installed on storage facilities to control emissions. Addition of any butane at all to the crude stream moves the vapor pressure at a given temperature from curve 2 toward curves 3 and 4. Because of the temperature limit imposed by wax formation, addition of any butane at all increases the likelihood that vapor recovery systems will be required, particularly if the vapor pressure standards is made more stringent. Thus, the North Slope producers have an interest in the CO_2 standard not only because of its impact on the cost of the conditioning facility, but also because of its impact on the capacity of the sales gas stream to transport NGL's particularly butane.

Increasing the CO_2 content of the gas stream may be cost-effective for the consumer also. Without pre-judging how additional NGL's might be charged for transportation through the ANGTS, i.e., whether transportation charges would be on a cents per mmBtu basis or on some other basis, transportation of more of the Prudhoe Bay hydrocarbon reserve through the ANGTS offers the prospect of increased utilization of the facility, and, hence, lower, overall costs to consumers.

Increasing the CO_2 content of the sales gas stream would have the effect of shifting to consumers certain costs or processing the conditioning the Prudhoe Bay gas, an outcome which the Commission has expressed its intention to prohibit with its proposed policy regarding the recovery of certain "production-related" costs as defined in the Natural Gas Policy Act.[56] However, it is possible that some cost-shifting through relaxation of the CO_2 standard would be the optimal solution for the overall conditioning and gas transmission system.

Increasing the CO_2 content of the sales gas stream would pre-empt some of the ANGTS throughput capacity, but additional processing and conditioning facilities could be installed to remove the extra CO_2 if the additional capacity were required. This could be done without any loss of NGL's carrying capability if incremental volumes of natural gas have a lower NGL's content than the Prudhoe Bay gas.

The State of Alaska and Arco, in their above referenced comments on Alaskan Northwest's March 2 filing, have requested a Commission statement regarding the appropriate proceeding for resolution of the CO_2 content issue. I believe this issue is separable from the throughput capacity issue, because any capacity committed to CO_2 transportation when operations begin can be retrieved by installation of additional conditioning facilities if sufficient quantities of natural gas become available to require that capacity. Thus, I believe that the maximum allowable operating pressure question should be resolved independent of the CO_2 question, the latter being better addressed in RM78-12, wherein the Commission is considering the project company tariffs, or perhaps as an ancillary issue in RM79-19, regarding the responsibility for production-related costs. It is the former proceeding in which the issue of appropriate standards for "pipeline quality gas" seems to me to be most directly before the Commission.

[FR Doc. 79-16624 Filed 5-30-79; 8:45 am]

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[56] See the Commission's Notice of Proposed Rulemaking in RM79-19, February 2, 1979.

[Docket Nos. G-4308, et al.]

Cities Service Co., et al.; Notice of Applications for Certificates, Abandonment of Service and Petitions To Amend Certificates [1]

May 22, 1979.

Take notice that each of the Applicants listed herein has filed a[n] application or petition pursuant to Section 7 of the Natural Gas Act f[or] authorization to sell natural gas in interstate commerce or to abandon service as described herein, all as [more] fully described in the respective applications and amendments whi[ch are] on file with the Commission and o[pen to] public inspection.

Any person desiring to be heard [or to] make any protest with reference to [said] applications should on or before Ju[ne ..], 1979, file with the Federal Energy Regulatory Commission, Washingt[on,] D.C. 20426, petitions to intervene or protests in accordance with the requirements of the Commission's [Rules] of Practice and Procedure (18 CFR [1.8 or] 1.10). All protests filed with the Commission will be considered by [it in] determining the appropriate action [to be] taken but will not serve to make th[e] protestants parties to the proceedi[ng.] Persons wishing to become parties [to a] proceeding or to participate as a p[arty in] any hearing therein must file petiti[ons to] intervene in accordance with the Commission's Rules.

Take further notice that, pursua[nt to] the authority contained in and subj[ect to] the jurisdiction conferred upon the Federal Energy Regulatory Commi[ssion] by Sections 7 and 15 of the Natural [Gas] Act and the Commission's Rules of Practice and Procedure a hearing w[ill be] held without further notice before t[he] Commission on all applications in [which] no petition to intervene is filed with[in] the time required herein if the Commission on its own review of t[he] matter believes that a grant of the certificates or the authorization for [the] proposed abandonment is required [by] the public convenience and necess[ity.] Where a petition for leave to interv[ene] is timely filed, or where the Commi[ssion] on its own motion believes that a f[ormal] hearing is required, further notice o[f] such hearing will be duly given.

Under the procedure herein prov[ided] for, unless otherwise advised, it wil[l be] unnecessary for Applicants to appe[ar or] to be represented at the hearing.

Kenneth F. Plumb,

Secretary.

[1] This notice does not provide for consolidation for hearing of the several matters covered herein.

Docket No. and date filed	Applicant	Purchaser and location	Price per 1,000 ft³	Pressure [base]
G-4308, C, Apr. 2, 1979	Cities Service Co., P.O. Box 300, Tulsa, Okla. 74102	Panhandle Eastern Pipe Line Co., Tucker "C" No. 1 Well, Morton County, Kans.	*	
G-4579, D, Apr. 16, 1979	Cities Service Co	Lone Star Gas Co., northwest quarter of the southwest quarter of sec. 36-2N-2W, Garvin County, Okla.	*	—
CI70-126, C, May 11, 1979	Columbia Gas Development Corp., P.O. Box 1350, Houston, Tex. 77001	Columbia Gas Transmission Corp., blocks 255 and 256, Vermilion area, offshore Louisiana	*	
CI72-519, D, Mar. 30, 1979	Cities Service Co	El Paso Natural Gas Co., certain acreage situated in the Washington Ranch field, Eddy County, N. Mex.	*	—

RHL

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Charles B. Curtis, Chairman;
Don S. Smith, Georgiana Sheldon,
Matthew Holden, Jr., and Geroge R. Hall.

Alaskan Northwest Natural Gas Transportation Company--- Pipeline Design and Capacity	)))	Docket No. CP78-123 et al.

NOTICE OF DELEGATE REPORT AND
ORDER INVITING COMMENTS

(Issued May 17, 1979)

The Commission is issuing for comment a report submitted to it by its Alaskan Delegate. The report discusses the pipeline size and operating pressure for that segment of the Alaska Natural Gas Transportation System (ANGTS) which is to be constructed in Alaska by the Alaskan Northwest Natural Gas Transportation Company. In addition to other applicable law, this order is issued pursuant to the mandate of Section 9 of the Alaska Natural Gas Transportation Act, 15 U.S.C. §719(g), and the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System (Decision), which mandates expeditious resolution of the matters discussed in the Delegate's report.

A. Background

On March 2, 1979 the Alaskan Northwest Natural Gas Transportation Company (Alaskan Northwest) filed with the Commission an application for an order to approve design specifications and initial system capacity for that portion of the ANGTS which is to be built by the applicant. 1/

1/ The portion involved is that segment of the ANGTS described in the President's Decision as lying within the State of Alaska. Decision at 6-7.

DC-B-40

Pursuant to Commission regulations, notice of the application was issued on March 16, 1979. Alaskan Northwest requests prompt action on its application so that it may proceed with steps necessary to financing and constructing the portion of the ANGTS for which it is responsible.

The Alaskan Delegate has submitted to the Commission a report concerning the diameter and maximum allowable operating pressure of the pipeline which is the subject of Alaskan Northwest's application. With respect to the design of the gas pipeline, the Delegate's report states that a 48-inch diameter was determined under the terms of the Decision. The Delegate's report states that with respect to the issue of what the maximum allowable operating pressure of the pipeline should be there is a threshold question: given the extensive record already compiled in this proceeding, 2/ whether significant new evidence is available on likely throughput volumes from the North Slope which would be served by this system since the time of the Decision that would suggest that an operating pressure of greater than 1260 psig should be authorized. The Delegate states that he believes there is no new information and that the Commission should authorize a maximum allowable operating pressure of 1260 psig for the pipeline.

The commission is issuing the Delegate's Report for comment by all parties of record in this proceeding. 3/

2/ That record includes the Initial Decision of the Commission, In re El Paso Alaskan Co., et al., Docket Nos. CP75-96, et al. (Feb. 1, 1977); FPC, Recommendation to the President (May 1, 1977); and the Decision.

3/ A copy of the Delegate's report is attached to this order. The views expressed therein do not necessarily reflect the views of the Commission.

Comments should be filed by July 2, 1979. The parties may also file comments on Alaskan Northwest's application of March 2, 1979. Any party of record perceiving the need for a hearing to determine either the diameter or the maximum allowable operating pressure of the gas pipeline which is the subject of Alaskan Northwest's application should file a request to that end, by July 2, 1979, specifying the issues to be presented for determination and a brief summary of the evidence which the requesting party would present. The request should include a statement of all issues of material fact allegedly in dispute, and provide a reasonable justification as to why these issues cannot be fairly and adequately resolved on the basis of the record compiled before Judge Litt, the President's Decision, and the Delegate's Report.

Finally, the Commission notes that the sole issues that it intends to resolve through the procedures set forth below are: (a) the pipe diameter, and (b) the operating pressure, of the Alaska pipeline segment discussed herein. In particular, the Commission does not intend to decide, on the basis of comments filed in response to this order, the issue of the appropriate CO_2 standard for the gas transported through the ANGTS.

The Commission orders:

(1) The Alaskan Delegate will serve copies of this Order, and of his report, on all parties to Docket Nos. CP78-123, et al.

(2) Parties of record in Docket Nos. CP78-123, et al. may submit comments on the Alaskan Delegate's report, and on the March 2, 1979 application filed by Alaskan Northwest Natural Gas Transportation Company. Such comments may be filed on or before July 2, 1979, and should be served on all parties of record in Docket Nos. CP78-123, et al. The comments may address any issue of fact, law or policy pertinent to the matters raised in the report and the application.

Project Office (AGPO) undertook this inquiry in an effort to facilitate a final FERC decision on the maximum allowable operating pressure.

Our process for studying the pressure question was to discuss it with interested parties and to prepare independent calculations of the expected transportation costs at different throughput rates, utilizing the alternative system configurations. We issued a draft report on the system design on September 27, 1978. We then provided a period for comments on the draft report and held an on-the-record conference among interested parties on December 15, 1978. At that conference I developed a proposition for resolution of the pressure question which served as the basis for the project sponsors' filing of March 2, 1979.11/

This report summarizes the positions of the parties as expressed in our discussions with them, their comments on our draft report, and their remarks at the conference. It then presents the AGPO's findings and relevant findings in the Initial Decision in El Paso Alaska Company, et al., Docket No. CP75-96, et al. (hereinafter referred to as the Initial Decision), the FPC Recommendation to the President, and the Decision. 12/

After my draft report had been circulated and comments initially solicited, a study of the required sales gas conditioning facility, 13/ sponsored by a group of producers and pipeline companies, was made available to me. This

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11/ See "Application of Alaskan Northwest Natural Gas Transportation Company For An Order Approving the Design Specifications and Initial System Capacity of the Alaska Segment of the Alaska Highway Pipeline Project", filed in Alaska Northwest Natural Gas Transportation Company, Docket No. CP78-123, et al. on March 2, 1979. This application was noticed by the Commission on March 16, 1979.

12/ These discussions and the present report are a part of the AGPO's effort to "expeditiously and yet comprehensively gather the necessary information which the Commission will require before it can intelligently analyze and rule upon the future applications for permanent certification", as required by the Commission by order of December 16, 1977.

13/ "Sales Gas Conditioning Facilities, Prudhoe Bay, Alaska"; The Ralph M. Parsons Company; September, 1978 Study Report. The sponsors were 7 producing companies and 11 natural gas transmission companies. The study is referred to herein as "the Parsons study."

study has not been formally filed with the Commission, nor evaluated by other experts. However, I believe it to be the most authoritative and accurate compilation and analysis of information available on the requirements for processing and conditioning the Prudhoe Bay gas, and on the characteristics of the sales gas stream. As the report was made available to me in my capacity as the Commission's Alaskan Delegate, it appears in my public file and is available for inspection by any interested party or member of the general public in the Commission's Office of Public Information.

The results of the study clarified certain concerns, and obviated others, particularly with respect to the disposition of the natural gas liquids (NGL's). I have maintained my description of the concerns expressed to me, but have tried to note the impact of the study results on those concerns as appropriate. I have also added a section to this report which applies the results of the study to the questions being considered here.

II. POSITIONS OF INTERESTED PARTIES 14/

1. State of Alaska

Alaska conditionally supports a pipeline with a maximum operating pressure of 1260 psig. 15/ Its support is conditioned upon the validity of certain assumptions mentioned in its comments on the project sponsors' March 2, 1979, application, all of which I believe to be true.

The State's principal objectives as expressed to us concerned the developing of an in-state manufacturing base to smooth out the "boom-and-bust" cycles of raw materials production industries. In the case of its Prudhoe Bay hydrocarbon resources, the State would like to develop a capability to convert some of those hydrocarbon resources into semi-finished and finished products. The State has previously used agreements for the sale of its royalty oil to encourage construction of additional refinery capacity in Alaska. An idea being discussed by State officials was development of a capability to manufacture various petrochemicals, utilizing produced NGL's as feedstocks.

The State contracted with the consulting firm of Bonner and Moore for an analysis of the possibility of a world-scale petrochemicals plant to be located in Fairbanks. The petrochemicals facility chosen for study would use ethane as a feedstock. At the time we talked with State officials, the State had no specific plans for utilization of propane and heavier NGL's but expressed a willingness to

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14/ During the course of our meetings with interested parties, most submitted written materials, usually in response to our requests. All of these materials were attached to the draft of this report, which was circulated to all parties in Docket No. CP78-123, *et al.*, in late September 1978. Those materials have not been attached here in order to prevent repetition, but have been made part of the Alaskan Delegate's public file, required to be maintained by Commission Order of December 16, 1977.

15/ See "Comments of the State of Alaska on the Design Specifications and Initial System Capacity of the Alaskan Segment of the Alaska Highway Pipeline Project", filed in Alaska Northwest Natural Gas Transportation Company, Docket Nos. CP78-123, *et al.*

develop such plans if required to achieve their objectives with respect to in-state use of some of the Prudhoe Bay resources.

Additionally, State authorities expressed an interest in maximizing recovery of the total energy resources of the Prudhoe Bay deposit. The modes of disposition of produced hydrocarbons are:

(1) Transportation through the oil pipeline or a new NGL's pipeline

(2) Transportation through the gas pipeline

) Use within the field as fuel for production and processing and conditioning facilities

(4) Fuel use for pump stations on the oil line and compressor stations on the gas line

(5) Reinjection

(6) Some combination of the above.

The distribution of the NGL's among these various dispositions is a function of the designs of the oil pipeline and the gas pipeline, and of production and processing and conditioning facilities on the North Slope. It will not be completely settled until the designs for all of these facilities have been finalized. State officials expressed an interest in transportation of the NGL's away from the North Slope in order to deliver them to higher value uses. State officials were also concerned that any disposition of gas or NGL's by reinjection involves some loss of ultimate recovery of that which is reinjected. 16/

Although the increased ability of the higher pressure alternatives to transport NGL's might make Alaska favor higher pressure, another aspect of the State's overall concerns might incline them toward the 1260-psig system.

16/ Gas reinjection could increase oil recovery slightly, but reservoir studies to date suggest that approximately the same amount of energy could be consumed in the reinjection process as would be provided by the additional oil recovered.

This concern is over the impact of gas production on oil recovery. The State conservation authority now expects that there will be sufficient gas available for sale from the Prudhoe Bay Main Pool Reservoir to support gas sales of 2.0 bcfd. However, there is a small possibility that actual production history of the reservoir will require a reduction in the level of gas sales. As this possibility is small, and would occur through circumstances which cannot now be foreseen, State authorities cannot say with precision what allowable gas production might be in the event that production experience requires reduced gas sales. Reduced availability of gas would argue for a lower capacity transmission system.

Our principal discussions on these issues with Alaska State officials took place in early February, 1978, before the Canadian Government's decision to utilize the 56-inch, 1080-psig system for the Whitehorse-to-James River segment. Prior to that decision, some consideration was given to a very high pressure (2150 psig) system proposed by Exxon in order to eliminate the need for any gas processing and conditioning facility at the producing area on the North Slope. Moving the processing and conditioning facility to somewhere south of Prudhoe Bay was suggested so as to locate it where costs were less than at Prudhoe Bay. Colocation of such a facility with a petrochemicals manufacturing facility was thought possibly to yield some economies of scale for construction of both. As the State's economic analysis of petrochemicals development was observed to be very sensitive to feedstock costs, we thought that any colocation economies might improve the State's prospects for petrochemicals development. Because of this interest, we discussed the possibility of moving the processing and conditioning facility away from the North Slope with representatives of the North Slope producing companies. These discussions are summarized below.

Alaska observed that a 1400-psig or 1680-psig system can carry a higher percentage of the butanes in the gas phase than a 1260-psig system, other things being equal. Butanes raise the Btu value and, thus, the heating value of the gas. With respect to the disposition of the butanes through the oil pipeline, Alaska noted that California air quality regulations restricting the vapor pressure of crude oil could limit the butane content of crude oil. Because of the potential for air pollution, the vapor pressure of all crude oil entering California must be held to a very low level unless vapor recovery systems are installed for oil storage facilities. Injecting butane into the North Slope crude oil has the effect of increasing its vapor pressure at any given temperature. Keeping the vapor pressure down after butane injection requires cooling the oil which, in turn, could cause wax formation problems in the oil pipeline.

2. Standard Oil of Ohio (Sohio)

Sohio believes that the maximum operating pressure should be 1260 psig.

At the time of our discussions with Sohio (March 15, 1978), the Canadian Government had made its decision to utilize the 56-inch, 1080-psig system for the Whitehorse-to-James River segment. Due to the hydrocarbon dew point characteristics of the gas stream at those operating conditions, the Canadian decision imposed a requirement for some NGL's removal prior to introduction of the raw gas stream into that Canadian portion of the system. The requirement for some processing and conditioning north of Whitehorse limits the question of where all processing and conditioning should take place.

The Sohio representatives maintained that, although construction costs on the North Slope are high, they are probably lower there than anywhere in inland Alaska, and probably also lower than anywhere in the Yukon Territory. The difference is that coastal locations can be served by barges transporting any large facility in modules, whereas an inland location requires transporting much smaller components with a concomitant requirement for much more extensive onsite assembly. 17/ According to Sohio, very large processing and conditioning facilities can be constructed and loaded onto barges in the lower-48 states, where

17/ Modular construction not only allows assembly of a facility at a location where costs are lower, but also allows the use of very large processing vessels, enabling realization of considerable economies of scale in facility design and operation. The Parsons study provides some further discussion of the benefits of modular construction.

complete fabrication facilities are available and assembly costs are much lower. Any inland Alaska or Yukon location would preclude the use of large modules and would require construction from components small enough to be loaded onto railroad cars or trucks for transportation to the inland location. Assembly of the small components would then have to be done in remote locations of Alaska or the Yukon. The difficulty of extensive assembly in remote locations makes inland locations less competitive with coastal locations. Sohio concluded that, because of the ability to make full use of economies of scale in designing the facility and modularizing it for transportation, the cost of facilities would probably be less for Prudhoe Bay or another coastal location than for any inland location.

Having concluded that Prudhoe Bay is the optimal location for any facility required to be located along the pipeline route north of Whitehorse, the next question was how much of the processing and conditioning should be done there. Except for the very high pressure (2150 psig) alternative proposed earlier by Exxon, transportation of the CO2, which comprises about 12 percent by volume of the unconditioned gas, is not cost effective according to Sohio. 18/ The savings in gas conditioning costs made possible by leaving the CO2 in the gas is more than offset by the reduced transportation efficiency for the other components of the gas caused by the presence of the CO2. As the very high pressure system (2150 psig) had been ruled out by the Canadian Government's decision for the Whitehorse-to-James River segment, CO2 removal is required north of Whitehorse and consequently should be done at Prudhoe Bay.

Once the CO2 is removed, the ability of the gas stream to transport NGL's is reduced. Thus, operating the gas pipeline system without condensation would require some NGL's removal as a consequence of the decision to remove the CO2, regardless of whether the 1260 psig or one of the higher pressure alternatives is utilized. The difference

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18/ In its comments on the draft report Alaska argued that it is cost effective to leave at least 3 percent of the CO2 in the gas stream. A 3 percent standard, according to Alaska, would save 10 percent of the capital costs of the conditioning plant and could result in a reduction of the cost of service to the consumer by noticeable amounts. See also Notice of Proposed Rulemaking and Statement of Policy, Docket No. RM79-19, issued February 2, 1979, wherein the Commission proposes a policy by which producers shall bear the costs of conditioning facilities, rather than consumers.

between the required processing and conditioning for the 1260 psig and 1680 psig alternatives is in the degree of NGL's removal. The requirement for the 1.40 psig system is between those of the 1260 psig and the 1680 psig systems.

The advantages of modular construction suggest that, since some processing is required on the North Slope, it is most cost-effective to do all of it there. The CO2 produced in the course of conditioning the gas may be able to be utilized in combination with extracted NGL's as a low-Btu fuel to power field production operations, processing and conditioning plant operations, or perhaps pumping or compressor stations. 19/

The Sohio representatives saw little to be gained by increasing the operating pressure of the gas pipeline to 1680 psig. They saw no major processing and conditioning savings projected for the 1680-psig system, but additional compression costs would be substantial. Although it is possible that compression facilities other than those currently used as part of oil production would not be required for operations at 1260 psig, 20/ additional compression capacity would have to be installed to attain the higher pressure, and operating costs would be significantly increased.

On the other hand, the Sohio representatives felt that the 1260-psig gas pipeline design, plus slight alterations to the oil pipeline, if required, were the most cost-effect. e solutions to the problem of moving the NGL's. The pentanes and heavier hydrocarbons could be moved through the oil pipeline essentially without alterations; the propanes and lighter hydrocarbons would go through the gas pipeline at 1260 psig. Sohio maintained that between

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19/ This possibility is developed in some detail in the Parsons study.

20/ Both Arco and Sohio pointed out in comments on this report in draft form that the raw gas compression facilities currently being utilized as part of oil production operations may continue to be required to maintain oil production even after gas sales commence. Thus, the availability of existing compression equipment for service in connection with gas sales is not assured.

62 and 75 percent of the butane could be moved through the gas pipeline with the 1260-psig design. 21/ Cooling the oil line would be the only alteration required to move the rest of the butane.

Some cooling of the oil line is expected to be required when its throughput capacity is increased from 1.2 million to 1.5 million barrels per day. Sohio argued that the relatively small additional capital investment for additional cooling to allow transporting butanes, plus the very low operating cost of the cooling facilities, would make transportation through the oil line the more cost-effective solution for the remaining butane, particularly when compared to the high investment and operating cost for extra compression to 1680 psig. The extra cooling requ_red to accommodate the butane would be less costly if installed at the time of the increase in oil line throughput capacity.

3. Atlantic Richfield Company (ARCO)

Arco representatives confirmed what we had heard from Sohio regarding the possibility of moving some or all of the required gas processing facilities away from Prudhoe Bay. It was their view that the decision in Canada to use larger diameter pipe for the Whitehorse-to-James River segment precluded the use of the very high pressure alternative, for which the North Slope processing and conditioning facilities could have been eliminated. Thus, moving any of the required processing and conditioning steps south of Prudhoe Bay would result in some duplication of facilities, as removal of both CO2 and most NGL's would be required somewhere north of Whitehorse. Arco representatives also concurred with Sohio's judgment that the savings available through modular construction would overwhelm any potential savings in moving facilities to inland locations with slightly more hospitable climates. Their estimate was that construction costs in Fairbanks or Haines, Alaska, would be as much as 50 percent higher than those at the North Slope because of the impact of modular construction.

21/ At the sales gas composition contemplated by the Parsons study, this proportion is even higher. See the discussion below of certain results of the Parsons study.

The Arco representatives were concerned about the ability to dispose of the produced butanes if the lower pressure gas pipeline system were utilized. Their concerns were in the following three areas:

(1) Crude oil vapor pressure limitations in California. (See p. 8 Supra.)

(2) The west coast market for petroleum products cannot use additional large quantities of butane.

(3) In considering use of a blend of CO2 and NGL for field fuel, the Arco representatives suggested that propane was a much better blending stock for the CO2 than butane. Extremely close Btu control is required for efficient turbine operation, and Arco technical personnel expressed concern over possible problems with condensation in fuel lines and burner orifices if butane were to be used.22/

The Arco representatives also had some different figures on the ability of the alternative gas pipeline systems to carry butane. Their figures showed the 1260-psig system would carry 25 to 60 percent of the available butane, while the 1680-psig system would carry 50 to 98 percent of the available butane. 23/

We asked some questions about alternative investment costs under different possible gasline system configurations. The figures we received suggested that a reduction in system operating pressure from 1680 psig to 1260 psig would require an additional investment on the order of $100 million (in 1978 dollars), consisting of $30 million in increased processing and conditioning facilities, and $37 to $75 million

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22/ In fact, the Parsons study concludes that propane injection into the fuel gas mixture is the optimal solution for Btu control of that stream. The sales gas mixture projected by Parsons has more capacity to transport butane than assumed by Arco, however, because of the reduced amount of propane required to be transported.

23/ See the discussion below of the Parsons study for further information on the NGL's carrying capacity of the sales gas stream.

for some combination of cooling for the oil pipeline, modifications to field fuel facilities, and reinjection facilities if required. 24/

Arco argued in its comments on the draft of this report that the increased natural gas liquid carrying capability of the higher pressure systems would benefit the consumer. Arco argued that even if the transportation costs are lower for a pipeline with a 48 inch diameter which operates at a maximum pressure of 1260 psig and which transports 2 bcfd of gas, a pipeline operating at a maximum pressure of 1440 psig would carry more butanes which would have the dual benefit of providing more Btu's to the gas consumer and reducing the volumes of butanes which would have to be disposed of less economically. Use of butane as a field fuel on the other hand, would require expensive conversion of existing fuel equipment; reservoir injection of liquid butanes could result in the ultimate loss of a significant quantity of these liquids; and transporting butane in the oil pipeline would require cooling the crude oil. Moreover, Arco argued that as long as the oil pipeline is operating at capacity, the transportation of butanes would require a reduction of crude oil shipments or an expansion of the capacity of the oil pipeline.

4. Exxon

Exxon has argued that the pipeline should have a maximum operating pressure of at least 1680 psig. Exxon representatives concurred with the opinions of the other two producers that an inland location for any processing and conditioning facility would likely be more costly than locating it at Prudhoe Bay. They also confirmed that the constraint on the butane content of the crude oil is the restriction on crude oil vapor pressure for reasons of air pollution control in southern California.

24/ In comments on my draft report, Sohio noted that Arco's $100 million figure must not have taken into account the reduced requirement for investment in sales boost compression facilities if the lower pressure gas pipeline system were utilized. Sohio's comments state:

> The net differential investment which would be required in the gas conditioning facilities and in various Prudhoe Bay field facilities to be compatible with a 1260 psig pipeline system is expected to add considerably less than the $100 MM (in 1978 dollars) estimated by ARCO, even when all butanes recovered are transported in the TAPS line in preference to blending them with the sales gas. Operating costs of oil coolers are also expected to be less than those related to additional gas compression. Sohio's Comments, page 2, October 27, 1978.

Representatives of Exxon were involved in the testing associated with the evaluation of safety and design aspects of alternative pipeline system designs which was carried out by the Arctic Gas Study Group. They suggested to us that there was little real safety difference between the 1260-psig and 1680-psig systems. The real safety question from their perspective is the proximity of either system to the oil pipeline. The principal safety issue is what would happen to the oil pipeline in the event of a natural gas explosion and fire.

Exxon's concern in the comparison between 1260-psig and 1680-psig systems was the cost-of-service advantage of the higher pressure system. They had previously advocated a very high pressure (2150 psig) system to increase the cost-of-service advantage even further.

In our discussion with them, they emphasized the highly prospective nature of the Beaufort Sea area and its potential for discovery of additional gas reserves. They favor higher pressure generally because it will result in a more fuel-efficient system at all levels of throughput, and will have a higher throughput capacity with a lower cost-of-service at higher throughput volumes.

5. <u>Alaskan Northwest Natural Gas Transportation Company (Alaskan Northwest)</u>

Alaskan Northwest is opposed to a pipeline with a maximum allowable operating pressure of either 1440 or 1680 psig. A major source of concern is its belief that a delay of up to 2 years could result from choosing a higher pressure system due to a need for extensive testing of the various components of such a system. The testing program required would include burst tests, test of crack arrestor designs, testing programs to validate valve designs, and lead times associated with high pressure compressor development. A delay of up to 2 years was estimated by the project sponsors to result in additional carrying charges of up to $1 billion.

Alaskan Northwest also shows a cost of service advantage for the lower pressure system at the throughput volumes they expect. The 1680-psig system does not become superior in performance until the throughput rate passes 3.6 bcfd according to its figures. In its recent application, 25/ Alaskan Northwest maintained that the point at which the 48-inch, 1260-psig system is equivalent in cost-of-service to the 48-inch, 1440-psig system is approximately 3.3 bcfd. Thus, the company concludes that the proposed system is the best economic selection up to a volume of approximately 3.3 bcfd prior to any consideration of potential delays. In its petition, Alaskan Northwest, citing findings in the Decision and the FPC Recommendation to the President, argues that 2.0-2.5 bcfd of gas will initially be available to the system and that the system should be capable of expansion by 1.0 to 1.5 bcfd, to an ultimate system capacity in the range of 3.0 to 4.0 bcfd. In the application, Alaskan Northwest suggests that Alaska's interest in the development of a petrochemical industry should not dictate a decision in favor of a higher pressure line. Alaskan Northwest argues that the primary raw material for such a plant is ethane and that a 1260-psig system can transport all the ethane that could be available from Prudhoe Bay almost irrespective of the final configuration of any processing and conditioning plant, and therefore does not offer any impediment to the State's plans.

Alaskan Northwest maintains that the oil pipeline represents the most cost-effective way to move any available quantities of excess butane. Although an investment of up to $100 million (in 1978 dollars) could be required for additional processing and conditioning plant investment and cooling, fuel conversion or reinjection facilities, relative to what would be required for the 1260-psig system, a 1680-psig pipeline system would require $237 million more capital investment (expressed in 1975 dollars) than the 1260-psig system.

Alaskan Northwest also maintains that there is plenty of room in the California market for additional butane. Its figures show that California refineries produced about 100,000 barrels per day of butane in 1975. The extra butane left on the North Slope after that which can be transported in the 1260-psig gas pipeline system would be something less than 22,000 barrels per day at a gas sales rate of 2.0 bcfd

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25/ "Application of Alaskan Northwest Natural Gas Transportation Company for an Order Approving the Design Specifications and Initial System Capacity of the Alaskan Segment of the Alaska Highway Pipeline." op. cit.

depending on the other components of the sales gas stream, 26/ before any allowance for field fuel uses.

Another concern expressed by the project sponsors is the additional safety hazard associated with a higher pressure system. Higher pressure causes higher potential energy to be stored in the pipe, resulting in increased likelihood of damage to the oil pipeline in the event of a gas pipeline rupture. The project sponsors maintain that crack arrestors will be required for the 1440-psig or 1680-psig system, whereas they may not be required for the 1260-psig system.

The project sponsors are also concerned about the vulnerability of the higher pressure system to cost overruns. Their submissions included a risk analysis of various factors which are likely to cause additional cost overruns with the higher pressure system. They feel that the risk of cost overrun is greatly reduced by staying closer to existing and proven lower-48 states pipeline technology.

Finally, Alaskan Northwest reacted negatively to my proposal discussed at the conference to build a pipeline which would operate initially at a pressure of 1260 psig but whose operating pressure could be increased to 1440 psig if there were an increase in gas volumes available for transporting. It argued that a pipeline should be operated at its maximum design pressure. It also noted that delay would be caused by the need to test such a system.

6. The U.S. Department of Transportation

Noting that it is a basic tenet of transportation system planning that a system should be designed to accommodate future growth, the Department of Transportation (DOT) argued that all the technical and economic data appear to them to support building a 1680-psig system. Moreover, the availability of capacity resulting from the construction of a 1680-psig system would encourage development and exploration in the total North Slope area. Citing a February, 1978

26/ The extra butane would be only about 4500 barrels per day at the sales composition projected by the Parsons study. See the discussion of the results of that study presented below. The Parsons study notes that the capacity of the system to transport butane could be increased by leaving more CO_2 in the sales gas, and recommends further study of the most cost-effective sales gas composition.

Technical Study Group evaluation of the 1680-psig system, 27/ DOT argued the system could be built and operated safely and reliably.

As noted above, a proposal was considered at the conference to build a pipeline the operating pressure for which would initially be 1260 psig and would be capable of expansion to 1440 psig if there were an increase in gas volumes available for throughput. The concept was to alter the compressors and the spacing of the compressor stations in order not to foreclose the possibility of increasing the operating pressure later on. DOT indicated that its safety regulations required a thicker pipe wall for a pipeline operating at 1440 psig than for a pipeline operating at 1260 psig, and that it would be reluctant to waive these regulations where the pipeline was built along the Alyeska haul road. A substantial portion of the pipeline in Alaska will be built along the haul road.

27/ "U.S. Government Safety and Reliability Evaluation of Different Pipe Size and Pressure Combinations for Alaska Gas Pipeline" attached to February 13, 1978, letter from Don S. Smith, Vice-Chairman of the FERC, to J.G. Stabback, Chairman of the National Energy Board of Canada, transmitting the U.S. Government's views regarding pipe size selection for the Whitehorse-to-James River segment.

III. Results of the Parsons Study

The Parsons study was undertaken by a group of gas producing and transmission companies 28/ in order to develop a preliminary design for the facilities necessary to process and condition gas produced from the Prudhoe Bay Unit for transportation through the ANGTS. The principal tasks performed in the course of the study were

- o screening the processes available and selecting processes to recommend for CO2 removal and hydrocarbon dewpoint control, respectively, and
- o developing a process design for processing and conditioning the gas to meet an assumed set of pipeline delivery conditions and quantity and quality specifications.

The study represents a careful evaluation by a consultant to a group composed of both producers and transporters of the optimal distribution of the components of the raw gas stream, for conditions as they currently exist or are expected to exist, among field and process fuel uses on the one hand, and the sales gas stream on the other. The relevance of the study to this inquiry is in the study's indicated resolutions of questions regarding the optimal allocation of the NGL's and the impact of those resolutions on the requirement to transport NGL's away from the North Slope.

The study team concluded that a physical solvent process is best for CO2 removal. A characteristic of physical solvent processes is absorption of a significant quantity of hydrocarbons along with the CO2. Much of the heavier hydrocarbon content is liquefied during the solvent regeneration process, and can thus be recovered. Significant amounts of ethane and propane remain in a gaseous phase, however, mixed with the extracted CO2. 30%

28/ Amerada Hess Corporation, Atlantic Richfield, Exxon Company U.S.A., Getty Oil Company, Mobil Oil Corporation, Natural Gas Corporation of California, Northern Natural Gas Company, Northwest Pipeline Corporation, Pacific Interstate Transmission Company (Arctic), Panhandle Eastern Pipeline Company, Phillips Petroleum Company, Sohio Petroleum Company, Southern Natural Gas Company, Tennessee Gas Pipeline Company, Texas Eastern Transmission Corporation, Texas Gas Transmission Corporation, Transcontinental Pipeline Corporation, United Gas Pipeline Company.

Because of its hydrocarbon content, the waste stream from the CO2 removal process has useable fuel value. The study recommends that this CO2/hydrocarbons mixture be used as fuel for the processing and conditioning facility itself. Any excess of this mixture over the requirements of the conditioning facility would be utilized in the other facilities at the Prudhoe Bay Unit after appropriate blending with other fuels (particularly propane) for heating value control.

Gas delivery and quality specifications assumed for purposes of the study were:

Delivery volume (nominal)	2.0 bcf
Delivery Pressure	1440 psig
Delivery Temperature (max.)	25°F
CO2 content (max.)	1.0 Volume %
H2S content (max.)	1.0 grain/100 SCF
Hydrocarbon Dewpoint (max,)	-10°F at 1,100 psia
Water dewpoint (max.)	-35°F at 1,100 psia

These specifications are similar to those which were part of the Alcan filing of March 8, 1977, except for the delivery pressure. The 1260 psig delivery pressure in that filing requires a more stringent hydrocarbon dewpoint standard, -10°F at 1,000 psia.

The results of the Parsons study with respect to allocation of recovered NGL's between fuel uses and addition to the sales gas stream is given in the following table, taken from the study itself:

	Propane	Butanes Min.	Butanes Max.	Pentanes-plus
Net Extracted				
BPD	52,350		31,290	28,700
MMSCFD (1)	80.3		41.3	--
Disposition		Min.	Max.	
To Pipeline Gas				
BPD	24,270	-0-	30,602	-0-
MMSCFD (1)	37.2	-0-	40.4	-0-
To Fuel Gas Systems				
BPD	28,080	-0-	-0-	-0-
MMSCFD (1)	43.1	-0-	-0-	-0-
To Crude				
BPD	-0-	688	31,290	28,700

(1) Standard conditions - 14.5 psia and 60°F.
MMSCFD = million standard cubic feet per day.

Source: Table 6-3 from Volume I, p. 6-4.

When combined with the NGL's not recovered from the gas mixture produced by the CO_2 removal process, the total allocation of NGL's between fuel uses and sales gas is estimated as follows:

Input (Billion Btu per day)		Sales Gas	Sales Liquids	Sales Total	Field Fuel	Fuel Use as percent of Input
C1	2101.7	1909.0	0	1909.0	192.7	9.2
C2	323.1	163.3	0	163.3	159.8	49.5
C3	249.2	91.4	0	91.4	157.8	63.3
C4	156.2	136.1	9.5	145.6	10.6	6.8
C5-plus	125.4	5.0	119.9	124.9	0.5	0.4
	2955.6	2304.8	129.4	2434.2	521.4	17.6

Source: AGPO estimate from material balances in Parsons study

As can be seen from the table reproduced from the study, the sales gas stream will accommodate almost 98 percent of the recovered butane under the conditions assumed for the study. References to figure 2-1 from volume II of the study, reproduced on the next page, indicates that the 1260-psig system will accommodate 86 percent of the recovered butane, leaving only about 4500 barrels per day of butane for reinjection or transmission through the oil pipeline.

In a section entitled "Future Design Considerations" (Volume I, Section 12), the study recommended that the cost impact of possible alternative specifications for CO2 content and gas pipeline pressure be evaluated for the overall conditioning and gas transmission system. The study observed that a higher allowable CO2 content of the delivered gas will have a "significant" impact on the facilities costs. The State of Alaska has estimated that relaxing the CO2 standard from 1 percent to 3 percent would save 10 percent of the capital costs of the conditioning plant (see footnote 18, <u>supra</u>.). Our reading of the Parsons study would confirm this estimate.

Case	Base (Max. Field Fuel)				Alt. (Min. Field Fuel)			
D.P. Curve	1	2	3	4	5	6	7	8
DeC_3 Ovhd, M/H	4075	4075	4075	4075	5475	5475	5475	5475
DeC_4 Ovhd, M/H	0	2259	3388	4517	0	2115	3173	4231
DeC_4 Ovhd, %	0	50	75	100	0	50	75	100

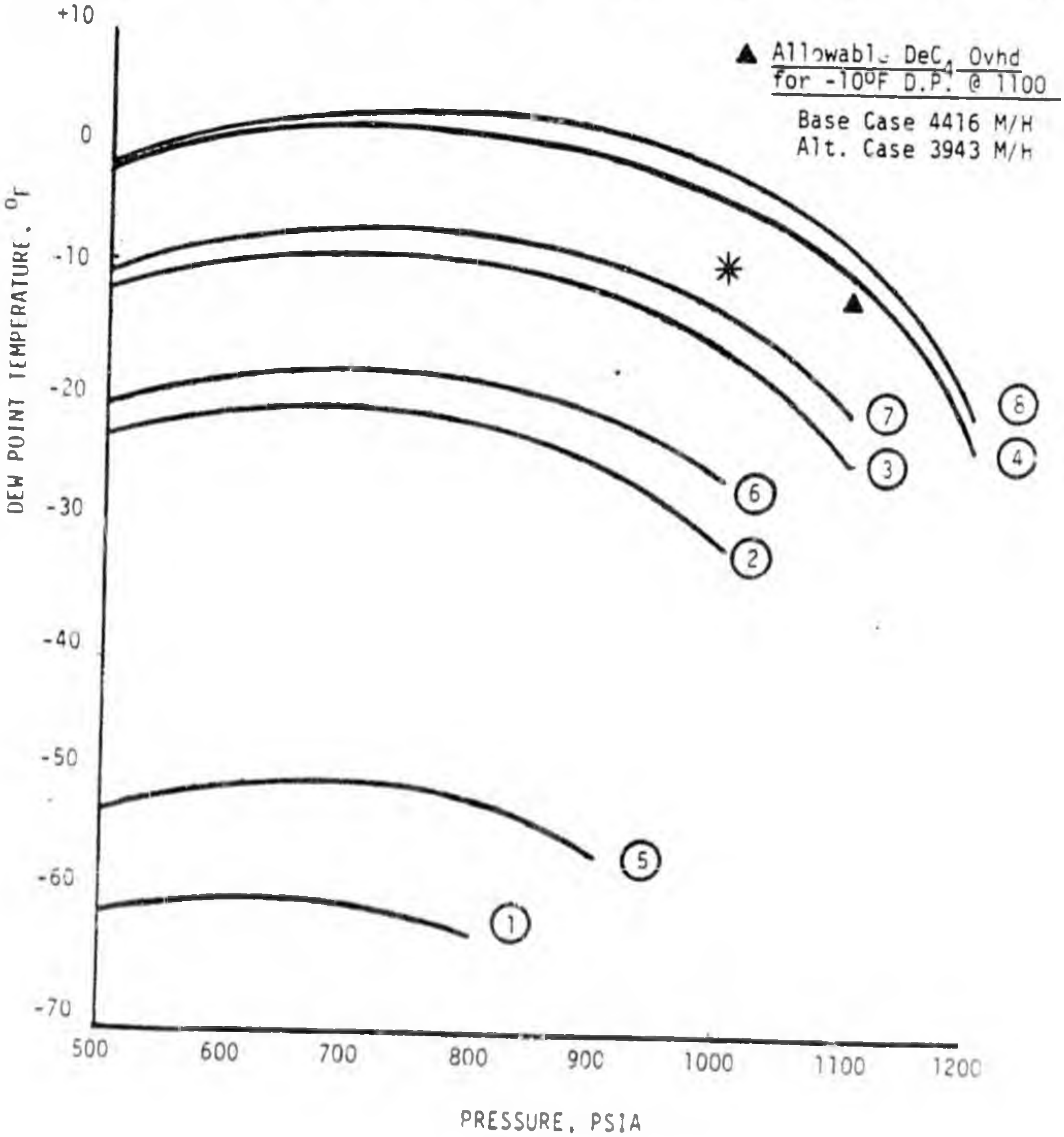


FIGURE 2-1

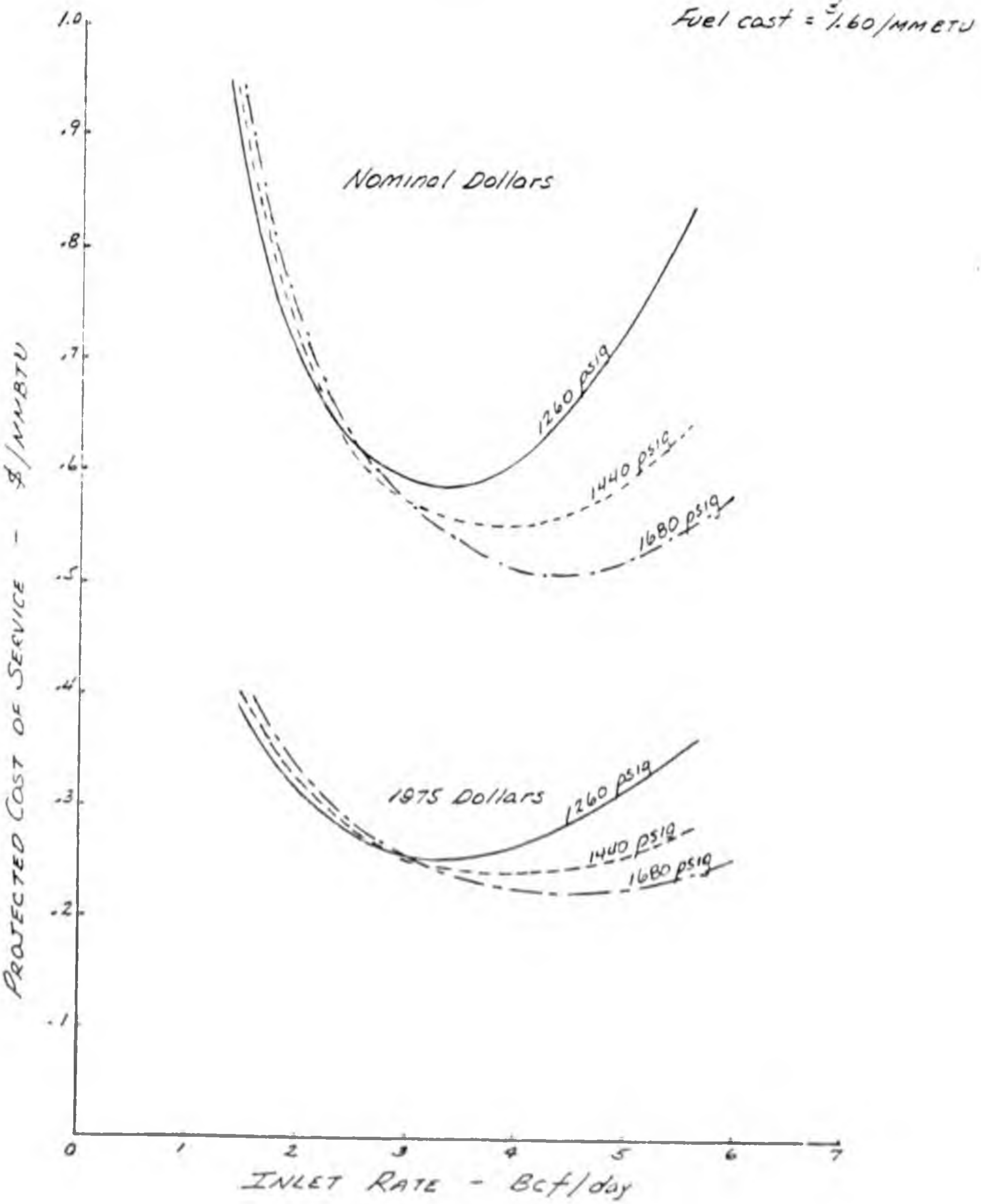
IV. ALASKA GAS PROJECT OFFICE ANALYSIS OF ALTERNATIVE SYSTEMS

The staff of the Alaska Gas Project Office prepared independent estimates of the capital costs and cost-of-service for the higher pressure systems for comparison with those submitted by Alaskan Northwest. Our results are plotted in figure 1 for a fuel cost of $1.60 (1975 dollars) per million British thermal units (mmBtu). Table 1 presents cost-of-service calculations for fuel prices of $1.00, $1.60 and $2.6[illegible] per mmBtu. The computed costs-of-service reflect the different heating values of the gas mixtures which would be transported at the different operating pressures. 29/

As can be seen on figure 1, higher throughput volumes favor one of the higher pressure alternatives. Likewise, table 1 shows that higher fuel costs reduce the threshold throughput rates at which the higher pressure systems have lower costs-of-service than the lower pressure alternatives.

29/ The assumed heating value of the gas stream for these calculations was 1135 Btu/cubic foot at 1260 psig, 1146 Btu/cubic foot at 1440 psig, and 1154 Btu/cubic foot at 1680 psig. These values differ from those subsequently arrived at in the Parsons study, and would tend to make our cost-of-service calculations lower than they would be if we had used heating values closer to Parsons'.

The comparisons shown on Figures 1, 2 and 3 in Tables 1, 2 and 3 include differences in gas conditioning plant costs for different pressure systems. Including such differences provides a more precise economic comparison of the various systems. The comparisons shown, however, may not represent true cost differences from the point of view of consumers since the cost of gas conditioning may be borne by the gas producers rather than the consumers. (See the Commission's Notice of Proposed Rulemaking in RM79-19, February 2, 1979.) However, as shown in Table 3, such differences in estimated gas conditioning costs resulting from a change in pressure represent only [illegible]y small portion of total costs. The effect of [illegible]ating gas conditiong cost differences would be to mov[illegible]e curves slightly closer together, but would not change any conclusions resulting from analysis of Figures 1, 2 and 3 and Tables 1, 2 and 3.



Fuel cost = $1.60/MMBTU
Nominal Dollars
1260 psig
1440 psig
1680 psig
1975 Dollars
1260 psig
1440 psig
1680 psig
PROJECTED COST OF SERVICE - $/MMBTU
INLET RATE - Bcf/day
1.0
.9
.8
.7
.6
.5
.4
.3
.2
.1
0
1
2
3
4
5
6
7

TABLE 1

PROJECTED COST OF SERVICE,

$/MMBTU

Fuel Cost, $/MMBtu	$1.00			$1.60			$2.62		
Pressure, psig	1260	1440	1680	1260	1440	1680	1260	1440	1680
PRUDHOE BAY TO ALASKA-CANADIAN BORDER (Including only the additional processing and conditioning costs required at lower-pressure)									
(1) Nominal Dollars									
Throughput, bcfd									
1.6	.792	.818	.844	.825	.849	.874	.881	.902	.924
2.4	.590	.591	.611	.631	.627	.646	.700	.689	.705
3.2	.531	.515	.510	.589	.563	.552	.687	.645	.623
4.0	.530	.491	.462	.610	.554	.514	.746	.662	.602
4.8	.593	.497	.449	.703	.580	.513	.891	.721	.621
5.6	.693	.544	.474	.843	.650	.553	1.097	.830	.687
(2) 1975 Dollars									
Throughput, bcfd									
1.6	.254	.367	.379	.367	.379	.390	.389	.399	.410
2.4	.262	.263	.273	.278	.277	.286	.305	.302	.309
3.2	.234	.228	.226	.257	.247	.243	.295	.279	.271
4.0	.232	.216	.203	.263	.240	.224	.316	.282	.258
4.8	.257	.216	.197	.300	.249	.222	.373	.304	.264
5.6	.299	.235	.207	.357	.277	.237	.476	.347	.290
PRUDHOE BAY TO WHITEHORSE, YUKON, CANADA (Including only the additional processing and conditioning costs required at lower pressure)									
(3) Nominal Dollars									
Throughput, bcfd									
1.6	.973	.997	1.034	1.009	1.029	1.065	1.071	1.085	1.118
2.4	.726	.727	.741	.774	.768	.779	.855	.838	.842
3.2	.637	.634	.625	.696	.691	.672	.797	.787	.753
4.0	.681	.620	.573	.782	.700	.635	.953	.834	.740
4.8	.765	.659	.567	.910	.767	.644	1.157	.952	.777
5.6	.909	.708	.615	1.109	.847	.716	1.448	1.083	888
(4) 1975 Dollars									
Throughput, bcfd									
1.6	.436	.448	.465	.451	.460	.477	.475	.482	.498
2.4	.323	.325	.332	.342	.341	.346	.374	.368	.371
3.2	.282	.281	.278	.305	.303	.296	.345	.341	.328
4.0	.298	.273	.253	.337	.304	.277	.404	.356	.318
4.8	.331	.287	.249	.388	.330	.279	.484	.401	.331
5.6	.392	.307	.268	.469	.361	.308	.601	.453	.375

Our method for preparing the capital cost estimates on which the cost-of-service estimates are based was to start with Alaskan Northwest's March 1977 estimates and adjust those estimates for the cost items which would change as a result of utilizing heavier pipe and higher operating pressures. This is essentially the same method utilized by Alaskan Northwest in preparing its capital cost estimates for the alternative systems. The explanatory material at the end of this section presents our capital cost estimates, along with a discussion of how they were determined.

Table 2 presents a comparison of our constant-dollar capital cost estimates (excluding compression) for the 1260-psig and 1680-psig systems with Alaskan Northwest's. 30/ As the table indicates, the largest difference in the constant dollar capital cost estimates for the 1680-psig system is only about 2 percent of the total estimate. Thus, the two sets of capital cost estimates must be considered very close.

Figure 2 is a plot of the cost-of-service for the 1260-psig and 1680-psig systems utilizing Alaskan Northwest's capital cost estimates, rather than ours. For a fuel cost of $1.60 per mmBtu, use of their capital cost estimates moves the nominal-dollar threshold for crossing over from the 1260 psig to the 1680 psig as the least-cost system to 2.9 bcfd from our 2.65 bcfd. In constant dollars, the respective crossover points are closer, both being just under 3.0 bcfd.

Alaskan Northwest has expressed considerable concern over the possibility of delay inherent in a decision to utilize a higher pressure system. Alaskan Northwest has stated that a decision to utilize a higher pressure system would likely result in a delay of 2 years, resulting in an increase in nominal dollar capital costs of at least $1 billion.

U.S. Government technical experts considered this problem when the Canadian Government solicited our comments as input to its decision on pipe size for the Whitehorse-to-James River segment. At that time our experts concluded that some delay for requisite safety and reliability testing was possible, but could likely be avoided. Their conclusion was:

30/ As shown in table 2, we have reallocated some capital costs for the 1260-psig system among the cost categories, although our total capital costs are the same except for the extra costs of processing and conditioning. We have discussed this reallocation with Alaskan Northwest and they do not object.

TABLE 2

COMPARISON OF PIPELINE COST ESTIMATES
1975 Base Costs - $ Millions

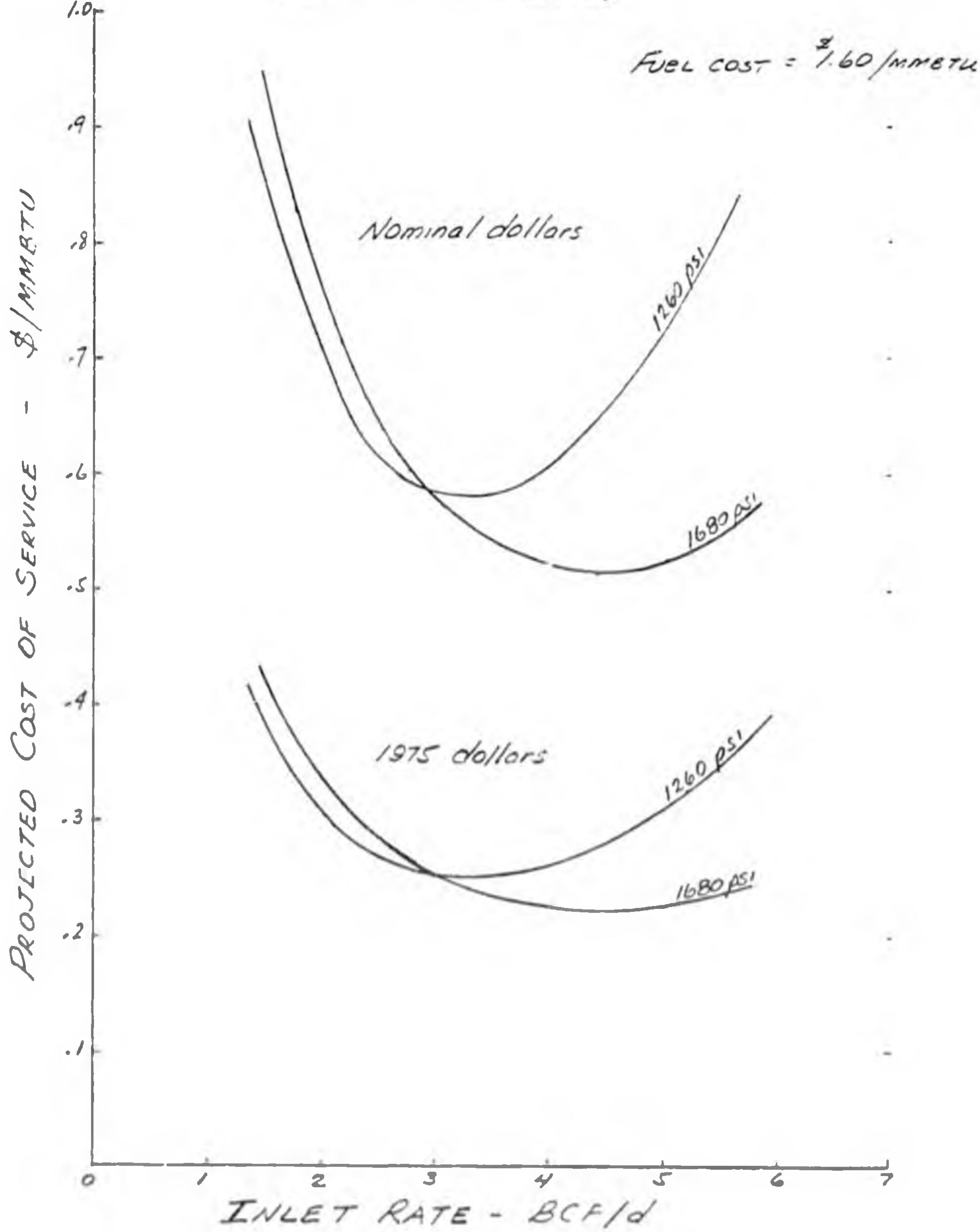
	1260 PSIG		1680 PSIG		Difference	
	NAP	FERC	NAP	FERC	NAP	FERC
Changeable Costs						
Pipe cost - delivered	529.1	475.4	704.1	650.4	175.0	175.0
Welding	21.5	25.4	41.6	36.1	20.1	10.7
Double Jointing	14.1	9.7	26.9	13.7	12.8	4.0
Weights	25.1	25.1	18.8	18.8	-6.3	-6.3
VFF, Installed	24.7	24.7	39.4	34.6	14.7	9.9
Bending	4.8	4.8	6.5	6.5	1.7	1.7
Short tie-ins	3.9	3.9	5.4	5.4	1.5	1.5
Tie-ins	9.5	9.5	18.5	14.2	9.0	4.7
Set Up and Alignment	20.3	20.3	28.0	28.0	7.7	7.7
Special Construction	7.3	7.3	9.6	9.6	2.3	2.3
Crack Arrestors	0	0	12.7	12.7	12.7	12.7
Add'l Side booms, labor	—	—	37.5	10.0	37.5	10.0
Add'l fuel	—	—	5.7	2.0	5.7	2.0
Add'l testing	—	—	10.0	10.0	10.0	10.0
River Crossings	13.0	—*	17.3	—*	4.3	0
	673.3	606.1	982.0	852.0	308.7	245.9
Add'l Prudhoe Bay Processing	0	30.0	0	0	0	-30.0
Other Costs (non-variable)**	991.2	1180.7	991.2	1180.7	0	0
E & S Contingency	183.3	60.6**	193.0	85.2***	9.7	24.6
Total Pipeline Capital Costs (excluding compression)	1847.8	1877.4	2166.2	2117.9	318.4	240.5

* No change in cost assumed - included in other costs
** Derived from subtracting changeable costs from total.
*** Amount on changeable cost items only - add'l amounts included in other costs.

FIGURE 2

COST OF SERVICE - ALASKA

(Utilizing applicant's cost data except for compressor costs)



> We are in agreement that testing all three, or even two, pipe designs will delay completion of construction, perhaps for as long as the two years which the Canadians have predicted. Selection of any one of the size and pressure combinations to the exclusion of all others now or within the near future will permit the pipeline applicants to conduct burst test verification and initiate purchase of the pipe earlier in order to complete the pipeline within the time frame described in the U.S./Canadian agreement. 31/

That report went on to say that, although our experts believe that a confirmatory testing program could be designed for the higher pressure alternative which would have very little likelihood of failure, there was more risk of failure for a higher pressure alternative than for a lower pressure one. Specifically, the experts said;

> We recognize that the possibility of delays associated with testing of the 48-inch 1680 psig pipe may be slightly greater because of the higher pressure. 32/

The impact of delay, as well as the impact of a possibly higher tendency toward cost overrun for the higher pressure systems, is illustrated in figure 3. For a nominal dollar case, we have plotted the cost-of-service for a 1680-psig system with capital costs $1 billion higher than anticipated. 33/

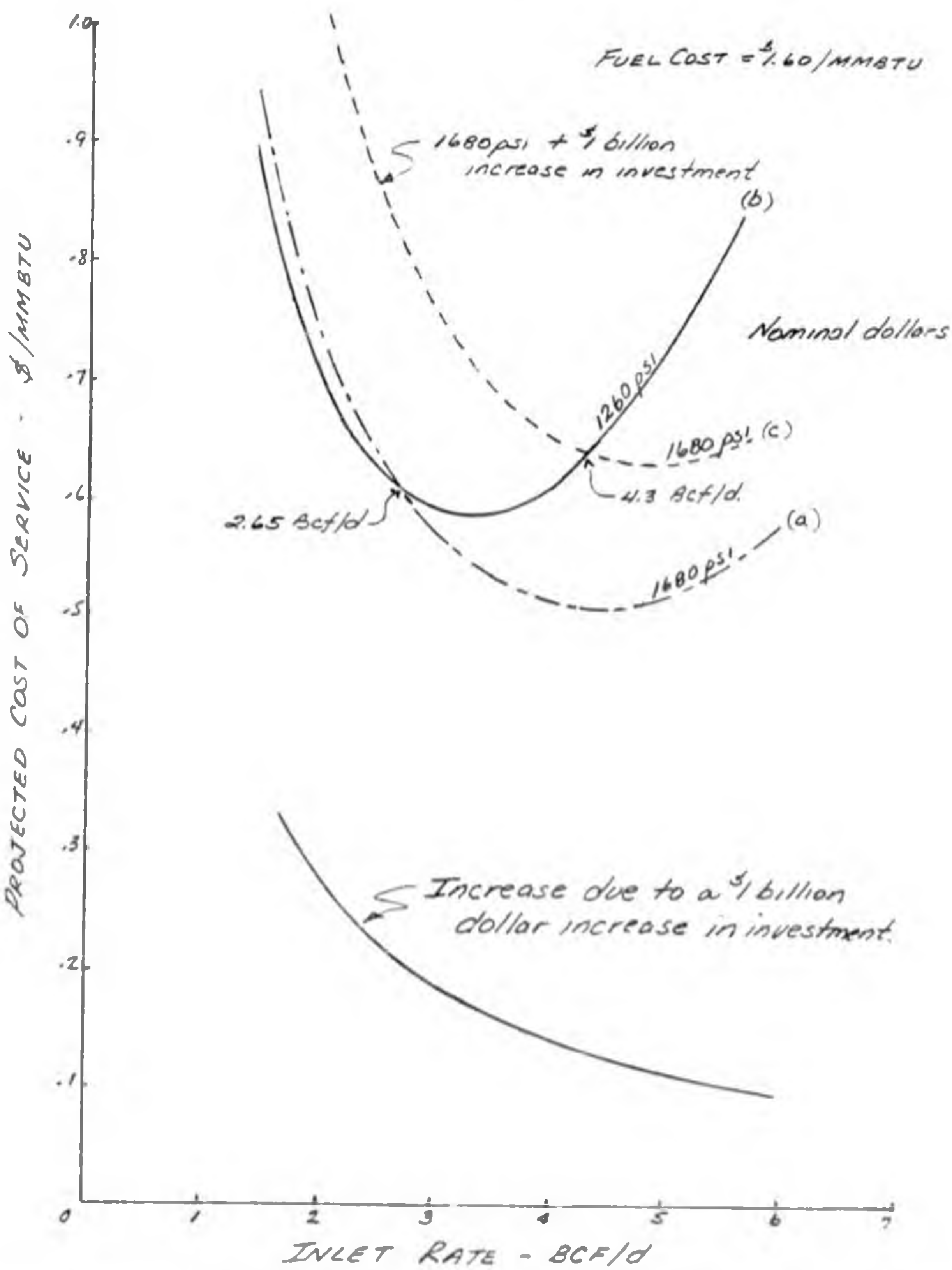
31/ "U.S. Government Safety and Reliability Evaluation of Different Pipe Size and Pressure Combinations for Alaska Gas Pipeline," Op. Cit., Executive Summary, pp. 1-2.

32/ Ibid., p. 5. In comments on the draft of this report, DOT added, "Realistically, the expected 'failure' that could occur relates to the effectiveness of pipe toughness alone to stop ductile fractures. The alternative simply is to add mechanical crack arrestors or rerun the tests with tougher pipe. The latter may mean a 3-6 month delay at worst." (October 26, 1978, Comments, p. 2)

33/ The choice of $1 billion as additional capital cost due to either delay or cost overrun is purely illustrative. Use of this example is not meant to imply that choice of the 1680 psig system would result in a $1 billion cost overrun. We do not now know whether choice of the 1680-psig system would result in any greater cost overruns than for the 1260-psig system.

FIGURE 3

IMPACT OF AN INCREASE IN INVESTMENT UPON THE COST OF SERVICE



As can be seen from figure 3, increased capital costs for the high-pressure systems relative to the low-pressure ones, whether due to time delays for testing or relatively higher cost overruns, would have the effect of moving upward the crossover point in throughput volume for going from the lower pressure system to a higher pressure one as the least-cost system. Our calculations show that the spread in unit cost of service, (constant 1975 dollars, fuel cost $1.60 per mmBtu) among the three systems amounts to less than 10 percent of the lowest one for throughput volumes up to about 3.5 bcfd. At higher throughput volumes, the cost of service plots for the three systems start to diverge more rapidly. Alaskan Northwest would put the throughput point at which the cost-of-service plots start to diverge closer to 4.0 bcfd.

The comparison of cost of service plots using our capital cost estimates with those using Alaskan Northwest's illustrates that small differences in assumptions or expectations about capital costs or other parameters can shift the crossover points noticeably. 34/ Thus, I conclude that the precise crossover points are less significant for decisionmaking than the points where the cost-of-service plots start to diverge.

Our cost-of-service plot for the 1260-psig system includes the effect of the additional cost of the conditioning facilities to meet the pipeline quality specification at that pressure. This assumption provides an indication of the total system-- pipeline plus conditioning facility-- cost consequences of the 1260-psig decision. This difference partially explains the difference between our results and Alaskan Northwest's. Other likely sources of difference include:

- o heating value of gas streams;
- o computation of fuel use for compression and chilling; and
- o our simplified cost-of-service computation methodology.

34/ A difference of $77.9 million in relative capital costs, which amounts to 4.2 percent of Alaskan Northwest's estimate for the 1260-psig system and a smaller proportion of the estimates for other systems, shifted the crossover point from 2.65 to 2.9 bcfd in the example given above.

EXPLANATION OF COST DIFFERENCES FOR VARIOUS SIZE SYSTEMS

Table A-1 presents estimated investment cost for systems designed to operate at 1260, 1440 and 1680 psig.

Table A-2 summarizes the horsepower (hp) and fuel requirements for the three systems.

Methodology

Total capital costs for the 1260-psig base case system at a 2.4 bcfd throughput rate were taken from the capital cost data filed with the FPC by Alcan Pipeline Company in March 1977. Independent cost estimates were made for all items where costs should change materially as a result of utilizing heavier pipe with a greater wall thickness. These cost estimates are shown in table A-1. The estimated costs of all other (nonvariable) items were assumed to be equal to the difference between filed costs and the total cost of the variable items for the 1260 psig, 2.4 bcfd base case.

Compressor and fuel costs were calculated based upon computed requirements for the three systems for flow rates of 1.6, 2.4, 3.2, 4.0, 4.8 and 5.6 bcfd. An FERC computer model based upon American Gas Association (AGA) pipeline flow equations was used to determine compression and chilling hp and fuel requirements. The additional gas processing and conditioning plant costs relative to those for the 1680-psig system were added to the capital costs of the 1260-psig and 1440-psig systems as that difference could have been reflected in an increment to any gathering and conditioning allowance, if allowed by the Commission. Plant cost differences are based on cost differences included in the materials supplied by Arco, adjusted to 1975 dollars. All other capital costs are expressed in 1975 dollars.

As a result of the above methodology, total costs shown are expected to be only roughly correct. However, cost differences should be reasonably accurate.

Capital cost data from table A-1 and fuel requirements shown in table A-2 were used in an FERC cost-of-service model to compute an expected cost-of-service for each case. As noted above, cost-of-service differences should be more meaningful than cost-of-service values for individual cases.

TABLE A 1

PIPELINE CAPITAL COST ESTIMATES - FERC

All Costs in Millions of 1975 Dollars

1. Pipeline

		To Canadian Border			To Whitehorse, Yukon		
Pressure	PSIG	1260	1440	1680	1260	1440	1680
Length	Miles	731.4	731.4	731.4	1000	1000	1000
Weight of Pipe	M Tons	646	738	860	859	982	1145
Pipe Cost (Delivered)	MM $	475.4	550.3	650.4	640.9	741.9	876.5
Welding	MM $	25.4	30.1	36.1	34.7	41.0	49.0
Double Jointing	"	9.7	11.3	13.7	12.1	14.2	17.2
Weights	"	25.1	22.0	18.8	36.1	31.6	27.1
Valves, Fittings, Installation	"	24.7	29.6	34.6	33.7	40.5	47.3
Short tie-ins	"	3.9	4.6	5.4	5.3	6.3	7.4
Tie-ins	"	9.5	11.4	14.2	13.0	15.6	19.4
Set Up & Alignment	"	20.3	23.8	28.0	27.8	32.3	38.3
Special Construction	"	7.3	8.4	9.6	10.0	11.5	13.1
Bending	"	4.8	5.5	6.5	6.6	7.5	8.9
Crack Arrestors	"	0	12.7	12.7	0	17.4	17.4
Add'l Sidebooms, labor	"	0	5.0	10.0	0	6.8	13.7
Add'l Fuel	"	0	1.0	2.0	0	1.3	2.6
Test Programs-add'l	"	0	10.0	10.0	0	10.0	10.0
Subtotal		130.7	175.2	201.6	179.3	236.0	271.4
Add'l Contingencies, Engineering & Supervision	"	60.0	72.6	85.2	82.0	97.8	114.8
Subtotal-Variable Items	"	666.7	798.1	937.2	902.2	1075.7	1262.7
Other Costs		1180.7	1180.7	1180.7	1393.2	1393.2	1393.2
Subtotal-	MM $	1847.4*	1978.8	2117.9	2295.4**	2468.9	2655.9
Difference		--	131.4	270.5	--	173.5	360.5
North Slope Costs (Ex Compression) Processing Plant Additions	MM $	30.0	20.0	0	30	20	0
Subtotal (Ex Compression)	MM $	1877.4	1998.8	2117.9	2325.4	2488.9	2655.9

* From Alcan March 1977 filing (Total Cost - AFUDC - Compressor Costs)

** 49.5 percent of Foothills filed costed for the Yukon, minus compressor costs, plus Alaskan costs

TABLE A-1 (Continued)

PIPELINE CAPITAL COST ESTIMATES - VARIOUS SYSTEMS & THROUGHPUT RATES

2. Compression and Cooling

		Alaska			To Whitehorse, Yukon		
	PSIG	1260	1440	1680	1260	1440	1680
Compression & Cooling, Prudhoe Bay Inlet	1.6	16.0	24.0	24.0	16.0	24.0	24.0
	2.4	24.0	32.0	48.0	24.0	32.0	48.0
	3.2	48.0	72.0	80.0	48.0	72.0	80.0
	4.0	72.0	96.0	120.0	72.0	96.0	120.0
	4.8	96.0	120.0	152.0	96.0	120.0	152.0
	5.6	112.0	144.0	192.0	112.0	144.0	192.0
Compression & Cooling, Compressor Stations	1.6	80.0	60.0	40.0	120.0	80.0	60.0
	2.4	180.0	120.0	100.0	240.0	180.0	120.0
	3.2	354.0	260.0	189.0	472.0	354.0	260.0
	4.0	607.0	449.0	283.0	884.0	647.0	410.0
	4.8	1120.0	682.0	475.0	1467.0	1096.0	693.0
	5.6	1815.0	1155.0	840.0	2388.0	1581.0	1235.0
Engineering, Supervision and contingencies for compressor stations	1.6	9.6	8.4	6.4	13.6	10.4	8.4
	2.4	20.4	15.2	14.8	26.4	21.2	16.8
	3.2	40.2	33.2	26.9	52.0	42.6	34.0
	4.0	68.1	54.5	40.3	95.6	74.3	53.0
	4.8	116.2	80.2	62.7	156.3	121.6	84.5
	5.6	192.7	129.9	103.2	250.0	172.0	142.7
Add Pipeline Cost (Less compression and AFUDC)		1877.4	1996.8	2117.9	2325.4	2488.9	2655.9

3. Total Direct Capital Cost

(Less AFUDC but including Prudhoe Bay extra Processing & Compression)	1.6	1983.0	2091.2	2188.3	2475.0	2603.3	2748.3
	2.4	2101.8	2166.0	2280.7	2615.8	2722.1	2840.7
	3.2	2319.6	2364.0	2413.8	2897.4	2957.5	3029.9
	4.0	2624.5	2598.3	2561.2	3377.0	3306.2	3238.9
	4.8	3209.6	2881.0	2807.6	4044.7	3826.5	3585.4
	5.6	3997.1	3427.6	3253.1	5075.4	4386.4	4225.6

Table A-2
Calculated Power and Fuel Requirements
at Different Operating Pressures and Throughput Rates

Operating Pressure, psig / Throughput rate, bcfd	1260 Compression	1260 Chilling	1260 Total	1440 Compression	1440 Chilling	1440 Total	1680 Compression	1680 Chilling	1680 Total
1. Prudhoe Bay Inlet									
Summer power requirements (in thousands of HP)									
1.6	64	18	81*	74	22	96	86	27	113
2.4	95	28	122	115	33	148	130	41	170
3.2	127	35	162	149	44	193	173	54	227
4.0	159	44	203	186	55	241	216	68	284
4.8	191	53	244	223	66	289	259	81	340
5.6	222	61	283	260	77	337	303	95	397
Average (summer and winter) Fuel requirements (in mmcfd)									
1.6			17.0			19.1			21.5
2.4			22.4			26.6			30.8
3.2			29.4			35.0			41.2
4.0			36.8			43.7			51.5
4.8			44.3			52.4			61.7
5.6			51.3			61.1			72.0
2. Prudhoe Bay to Canadian Border									
Summer power requirements (in thousands of HP)									
1.6	51	21	72	37	16	53	25	11	37
2.4	155	49	204	109	37	146	78	30	108
3.2	350	97	447	246	72	318	169	52	221
4.0	675	178	853	476	129	605	324	90	415
4.8	1158	297	1456	819	214	1033	557	147	704
5.6	1832	464	2296	1303	334	1637	882	227	1110
Average (summer and winter) Fuel requirements (in mmcfd)									
1.6			16.6			12.6			8.9
2.4			39.5			26.6			22.1
3.2			86.3			61.8			43.8
4.0			160.9			114.9			79.5
4.8			276.8			193.1			128.4
5.6			444.6			299.0			203.3
3. Prudhoe Bay to Whitehorse									
Summer power requirements (in thousands of HP)									
1.6	70	19	89	51	14	65	35	9	44
2.4	214	49	263	154	33	187	106	29	135
3.2	467	96	593	351	69	420	237	50	287
4.0	988	177	1165	703	125	828	473	85	557
4.8	1716	293	2008	1238	207	1446	821	145	966
5.6	2681	462	3143	1956	332	2287	1336	224	1560
Average (summer and winter) Fuel requirements (in mmcfd)									
1.6			20.0			14.4			10.0
2.4			50.2			35.6			26.0
3.2			109.4			78.2			54.5
4.0			[illegible]			151.8			103.1
4.8			369.6*			263.6			169.5
5.6			591.0			402.5			273.7

* Totals may not equal sum of parts due to rounding.

Alaska Gas Project Office Capital Cost Estimates

Items for which differences in pipe weight and operating pressure result in minimal differences in cost

The following activities during pipeline construction were assumed to have the same cost (or only minor cost differences) regardless of the pipe's weight or pressure rating:

1. Right-of-way procurement.
2. Clearing and grading.
3. Workpad and access roads.
4. Ditching.
5. Pipe alignment.
6. Field storage of pipe and materials.
7. Coat and wrap pipe.
8. Pipe inspection.
9. Padding and backfill.
10. Cleanup.
11. Resod.
12. Metering equipment.
13. Automation and telecommunications.
14. River crossings.

In actual practice, increasing the operating pressure should result in only minor differences in actual engineering and super sion costs. However, since these items are frequently considered as add-on items and are usually expressed as a percentage of other items, they were treated as a variable cost in this report.

Items where differences in pipe weight and operating pressure will change costs

Pipe Costs

Pipe costs were computed assuming a 1975 base mill price of $550 per ton for 0.6-inch wall thickness, internally coated pipe, plus the following charges:

1. $10/ton additional cost for 0.686-inch wall thickness pipe.

2. $20/ton additional cost for 0.80-inch wall thickness pipe.

3. $50/ton additional cost for increased pipe toughness.

4. $30/ton increased mill cost-Canadian pipe.

5. $20/ton Yukon tax.

To compute tonnage requirements for pipe it was assumed that the heavier wall thickness required in Class II and III construction locations would increase requirements by 10 percent compared to the tonnage required if the entire line was considered as Class I construction.

Pipe Transportation

It was assumed that the pipe would be shipped from the mill to delivery points in Alaska by intercoastal vessels. The following delivery costs were assumed.

	$/ton (1975)
Baytown, Texas, to Anchorage, Alaska	90
Baytown, Texas, to Prudhoe Bay, Alaska	140
Wellman, Ontario, to Skagway, Alaska	100

Pipe delivered to Anchorage (or Seward), Alaska, that will be further shipped to Fairbanks, Alaska, via the Alaska railroad, was assumed to incur an additional charge of $20 per ton. Rail charges from Skagway, Alaska, to Whitehorse, Yukon, were assumed to be $10 per ton.

It was assumed that the pipe would be strung from pipe storage points in Prudhoe Bay, Fairbanks, Anchorage (or Valdez), Alaska, and Whitehorse, Yukon. The following pipe stringing costs were assumed:

Stringing costs, $/ton (1975)

		Wall thickness, inches		
		0.6	0.686	0.80
From:	Prudhoe Bay	21.60	19.80	24.30
	Fairbanks - North	18.80	17.40	21.20
	Fairbanks - East	15.10	14.20	17.00
	Anchorage (Valdez)	15.10	14.20	17.00
	Whitehorse	15.10	14.20	17.00

Higher costs were assumed north of the Yukon River. Stringing costs varied because of assumed truck weight limitations. For instance, it was assumed that only two double joints of 0.8-inch wall thickness pipe could be delivered per load compared to three double joints of 0.6-inch thickness pipe. The weight limitations assumed are probably conservative.

Welding

Alaskan Northwest has stated that increasing pipe weight and wall thickness reduces construction speed, due to increased welding requirements. They maintain that such reduced construction rate increases costs significantly more than just the increased welding costs, since a slower pace increases the cost of most construction activities. In contrast, others have stated that increasing wall thickness should not slow down construction.

Our knowledge of the welding procedure is that the stringer bead (the initial weld) is made by a stringer bead crew, which for 48-inch diameter pipe would likely consist of four welders. Upon finishing the stringer bead, the stringer bead crew moves forward to the next joint. Immediately following completion of the stringer bead, the hot pass bead is placed by the hot pass crew. Since the hot pass bead is applied at a slightly higher speed than the stringer bead, the hot pass crew usually has no trouble keeping up with the stringer crew. The filler and cap bead are made by separate crews. Normally, a filler and cap crew will stay with a weld until it is finished. Since more weld material must be placed by the filler and cap welders, there may be several filler and cap crews per stringer crew. When thicker wall pipe is welded, it is only necessary to add more filler and cap welders.

According to our understanding of the process, the only welding problem with thicker wall pipe is that 0.8-inch wall thickness pipe would add about 100,000 to 120,000 man-hours of additional welder time compared to that required for 0.6-inch wall thickness pipe. Assuming a 2-year construction period and 1600 man-hours per year per welder, this additional welding would require adding about 38 welders. There should be no changes in nondestructive testing requirements, and only minor increases in inspection and supervisory personnel.

Construction speed is determined by the speed of the stringer crew. Since the time to make the stringer pass is independent of wall thickness, welding speed, expressed as joints per day or miles per day, should not be a function of wall thickness. As a consequence, increasing the wall thickness of the pipe should not materially reduce construction speed.

Welding costs shown in table A-1 assume manual welding; automatic or semi-automatic machines could probably reduce costs and improve weld quality. Welding time is based upon a theoretical arc time assuming deposition of 0.8 pounds of weld material per minute; changing electrodes is allowed for by adding one-third again to the time spend depositing weld material. We then assume that 50 percent of welders' working time is spend on activities other than these two.

Double Jointing

It was assumed that automatic or semi-automatic welding machines would be utilized for doublejointing under controlled, indoor conditions. The principal differences in doublejointing costs for thicker wall pipe compared to thinner pipe would be an increase in machine and operator time.

Bending

It was assumed that bending costs for the 0.8-inch wall thickness pipe would be 10 percent greater than for pipe with 0.6-inch wall thickness, or about $0.25/foot increase.

Sidebooms - Support Tractors

It was assumed that the heavier pipe would necessitate heavier lifting equipment, with a resultant increase in fuel and amortization costs. No increase in operating personnel was assumed.

Concrete Weights

March 1977 filed costs were assumed for the base case. Costs for the heavier pipe were computed assuming that total costs for weights would be proportional to the pipeline negative bouyancy without weights.

Valves and Fittings

Block valve costs of $90,000, $96,000 and $105,000 each were assumed for 1260 psig, 1440 psig and 1680 psig valves, respectively. Installed costs of valves and fittings were assumed to be seven times the valve costs. All costs are based upon 1975 prices.

Compression and Cooling

The high-pressure systems will increase compression and cooling requirements at Prudhoe Bay, but will reduce them at pipeline compressor stations. Computed horsepower requirements are shown on table A-2

Compressors are now used to reinject produced gas. Existing first stage compressors compress the gas from about 550 psig at flow station discharge points to about 1700 psig. These compressors possibly would not need to be duplicated.35/

35/ Sohio noted in its comments on our draft report that whether the compressors will need to be duplicated will depend on whether Prudhoe Bay working interest owners agree to release any of these facilities for gas sales service.

Arco also addressed this point in its comments on the draft report. It noted that the Prudhoe Bay owners installed compressors to reinject gas which is produced with crude oil. At the time gas sales commence the volume of gas which will have to be reinjected will be reduced by the volume of gas sales. However, these compressors may still be required for reinjecting a portion of the gas production in order to maintain crude oil production.

V. ESTIMATES OF THROUGHPUT VOLUMES

As is apparent from the plots of transportation costs versus throughput volume, expected throughput volume is an important parameter in determining which of the alternative systems is the most cost-effective design. This section reviews the available information for guidance on this point.

1. Findings in the Initial Decision

The quantity of gas reserves on the North Slope of Alaska and the deliverability of these reserves was explored in detail during the hearing before FPC Administrative Law Judge Litt in El Paso Alaska Company, et al., Docket No. CP75-96, et al. Judge Litt concluded in the Initial Decision that, although the uncertainty of reservoir performance and the possible necessity of water injection precluded exact estimates as to the daily deliveries to be expected from the Prudhoe Bay Field, the weight of the evidence supported a finding that 2.0 - 2.5 bcfd of gas will initially be available from the Prudhoe Bay Field. (Initial Decision at 33.) The proven reserves in the Prudhoe Bay Oil Pool support this finding. If one includes additional reserves from the Sadlerochit, Lisburne, and Kuparuk reservoirs, this estimate may be conservative. Judge Litt noted in connection with the Lisburne and Kuparuk reserves that future development or complete disclosure of past drilling would be necessary to establish the producing capabilities of these formations. (Initial Decision at 31.)

Judge Litt also found that the evidence suggested that deliveries above the 2.0 - 2.5 bcfd level might be available from the North Slope region because of reserves other than in the Prudhoe Bay Field. (Initial Decision at 33.) However, he found that the evidence regarding such reserves was unclear and made no specific findings as to the volumes of gas which might be delivered from such reserves.

2. Findings in the FPC Recommendation to the President.

The FPC stated in the Recommendation to the President:

"Thus, we conclude that it is reasonable to assume 2.0 to 2.5 Bcfd from Prudhoe Bay Oil Pool within five years after the commencement of oil production. There exists some possibility of increased delivery from the North Slope of perhaps as much as an additional 1.5 Bcfd from NPR-4 (Naval Petroleum Reserve No. 4), ANWR (The Arctic National Wildlife Range), and the Beaufort Sea, as well as other reservoirs in or near the Prudhoe Bay Oil Field. Thus, we find the system should be designed to carry initially 2.0 - 2.5 Bcfd, and be capable of expansion to an additional 1.0 - 1.5 Bcfd." (p. I-17)

3. Findings in the Decision

The report which accompanies the Decision notes that the increase in the nation's supply of natural gas from an Alaskan gas project is estimated to be 0.7 trillion cubic feet (tcf) per year (2.0 bcfd) by 1985. By 1990, a volume greater than 0.9 tcf per year (2.4 bcfd) might be produced, according to the report.

4. State of Alaska

The Prudhoe Bay Field is located on lands owned by the State of Alaska. Detailed information on the production potential of that field has been made available to the State in its capacity as royalty owner and conservation authority. At our request, the State's Department of Natural Resources prepared estimates of reserves and deliverability of gas from State lands in the North Slope region based on all information available to them. Those estimates suggest a deliverability range after 1988 of 2.0 to 4.2 bcfd from State lands (including the Prudhoe Bay Field) with the median estimate at 2.8 bcfd.

5. U.S. Geological Survey

As part of the July 1, 1977, reports to the President prepared under the terms of the Alaska Natural Gas Transportation Act (ANGTA), the U.S. Geological Survey (USGS) compiled estimates of reserves and deliverability for all North Slope areas.36/ The USGS discussion cites three separate analyses of North Slope potential -- its own, that of the Potential Gas Committee of the Colorado School of Mines, and that of the Division of Geological Survey of the State of Alaska -- to conclude that there is very high probability of substantial additional recoverable gas reserves in the North Slope area.

Converting potential reserve estimates into proven reserves dedicated to pipeline transportation is a demanding exercise in expectation. However, using the USGS figure of 19 tcf of potential reserves outside the Prudhoe Bay geologic structure, in conjunction with a rule of thumb for deliverability (1 bcfd of production for 20 years requires at least 20 tcf of potential reserves), plus the State's figure for the Prudhoe Bay Field itself, these estimates suggest there is a 95 percent probability that deliverability from all North Slope producing areas will be at least 2.5 bcfd if production from all of these reserves overlaps through some period in the future, as seems highly likely. There is a small probability of North Slope deliverability going as high as 7.5 bcfd.

36/ Report of the Working Group on Supply, Demand and Energy Policy Impacts Of Alaska Gas; Federal Energy Administration; Department of Commerce; Department of the Interior-U.S. Geological Survey; Department of Transportation; Department of the Treasury; Energy Research and Development Administration; July 1, 1977.

VI. ADDITIONAL CONSIDERATIONS

Our discussions with interested parties suggested that considerations other than design costs and estimated throughput volumes are important to the choice of system operating pressure. This section presents short discussions of the most important of those considerations as we understand them.

1. Vulnerability to Cost Overruns

The project sponsors have expressed the concern that a higher pressure system is more vulnerable to cost overruns. Some support for their concern can be found in the work of Professor Walter Mead of the University of California at Santa Barbara. In a recent study published by the American Enterprise Institute,37/ Professor Mead reported in a chapter on cost overruns (chapter 6) that an econometric analysis of past Defense Department projects "...indicated that cost overruns were significantly related to the length of time required for the development program and the extent of technological advance involved in the project."(p. 86) The implication is that the closer to known technology a project is, or more specifically, the more like a previously constructed project a succeeding one is, the better the cost estimates for the successor project and the less its tendency to cost overruns. To the extent that the 1260-psig system can be considered closer to known technology than either of the higher pressure alternatives, its tendency to cost overrun should be less if an analogy to Professor Mead's analysis of Defense Department projects is appropriate.

Any difference in their respective tendencies toward cost overrun between the 1260-psig system and the higher pressure alternatives would have the effect of raising the crossover point where increased throughput volume makes a higher pressure system result in lower unit transportation charges. Figure 3 in the section which presented the results of our calculations (section IV, *supra*) shows the effect on the crossover point of an increase in capital costs for a

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37/ Transporting Natural Gas from the Arctic: The Alternative Systems; Walter J. Mead, with George W. Rogers and Rufus Z. Smith; American Enterprise Institute for Public Policy Research, Washington, D.C.; August 1977.

high-pressure system. A similar effect on the crossover point would be realized if cost overruns had the effect of increasing the costs of a higher pressure system relatively more than those of the 1260-psig alternative.

2. Impact on Financing

The Decision requires that the Alaskan Natural Gas Transportation System be privately financed. Therefore, the impact of a decision to utilize a higher pressure system on the ability of the sponsors to obtain private financing is a major concern.

The risk of major cost overruns creates whatever risk there is of project non-completion, and presents the largest single financing problem for the project. Thus, if the lower pressure system is closer to current gas pipeline industry practices, the analysis referred to by Professor Mead would suggest that utilizing the lower pressure alternative reduces the likelihood of major cost overruns and thereby facilitates financing. The effect of technological advances on the reliability of cost estimates was alluded to by the NEB in its February 19, 1978, "Statement of Position."38/

In response to our request for more definitive information on the significance of the pressure question for financing, the project sponsors' principal financial advisers prepared a letter explaining the effect of a decision to utilize a higher pressure system on the financing proposals of the pipeline project. The gist of their concern is that a higher pressure system involves technological risks that lenders and potential equity investors simply will not accept.

3. The Gas Consumers' Interest

The interest of the gas consumer in the low-pressure/high-pressure decision is not obvious. Although a higher pressure system should result in lower transportation charges at higher levels of throughput, it is not assured that such reductions in transportation cost will accrue directly to the benefit of gas consumers.

38/ "Until sufficient field welding tests and production trials are done to establish suitable procedures and the manpower and equipment requirements to achieve progress rates compatible with other crews, the National Energy Board feels the present cost comparisons (between standard-pressure and high-pressure alternatives) based on normal procedures may not be valid." NEB Statement of Position, op. cit., Technical Review, pp. 3-4.

The means by which the delivered price is set for the gas to be transported by ANGTS does not lead to a clear-cut showing of consumer benefit. For the initial throughput volume, an expected 2.0 bcfd from the Main Pool Reservoir of the Prudhoe Bay Field, the delivered price will be the sum of the transportation charge and a wellhead price, plus an allowance for gathering and conditioning if allowed by the Commission. In this case, reduced transportation charges should be passed on to gas consumers as reductions in delivered prices.

In the next few years, however, high-priced sources of gas such as the Prudhoe Bay gas could rapidly exhaust the implicit subsidies provided by allowing the price of this gas to be averaged in with lower cost gas from conventional supply sources. As soon as the use of "rolled-in" pricing has raised the average price of all gas to approximate parity with the delivered price of alternate fuels, incremental gas sales are likely to be made only at prices set by competition with those of alternative fuels. At that point reductions in transportation charges would likely accrue to producers.39/

Depending on the relationship of the netback to the field price from the market value of this gas on the one hand, and the maximum lawful ceiling price set by the NGPA on the other, possible Commission use of rolled-in pricing for other gas supply projects, and changes in the delivered prices of competing fuels, prices for North Slope gas sales after the initial 2.0 bcfd from the Main Pool Reservoir could be set by a netback from the delivered prices of competing fuels. In that event, reduced transportation charges for these incremental volumes would benefit the gas producers.

An efficient natural gas transportation system which encourages the development of additional supply through higher field prices is not without some consumer benefit. The point here is that an analysis of that benefit is not as simple as might be implied by a comparative evaluation of transportation cost curves.

39/ A limitation on such a potential benefit to producers will be the ceiling price on natural gas produced from Prudhoe Bay Unit established by § 109 of the Natural Gas Policy Act of 1978 (NGPA). The price of competing fuels may only determine the price of gas from the Prudhoe Bay Unit to the extent such a price is equal to or less than the ceiling price.

Increased investment in gas conditioning plant:	$30 million
Field fuel system investment:	$50 million
Injection investment:	$25 million
Total:	$105 million

As the likely outcome of a decision to use the 1260-psig system would be a combinatior of cooling the oil pipeline, use of the extra butane in the field, and reinjection, we believe approximately $100 million (in 1978 dollars), including the $30 million required for additional investment in the processing and conditioning facility, is a representative requirement for comparison with the $237 million (in 1975 dollars) additional investment required to increase the system operating pressure to 1680 psig. None of these figures consider operating costs, so any comparisons are necessarily incomplete.

The gas consumer would see the increased investment requirement in the form of increased transportation charges for gas delivered by a higher pressure system, at least for the first 2.0 bcfd of throughput. Although the increase in unit transportation charges would be tempered by the delivery of higher Btu gas, the additional Btu's per unit volume would not be enough to offset the higher transportation charges until throughput volumes get higher than just those from the Main Pool Reservoir of the Prudhoe Bay Field. 41/

On the other hand, the oil consumer would not likely be directly affected by a requirement for additional investment in oil pipeline facilities. North Slope oil prices are effectively set through competition with imported oil, and can not be increased to consumers in order to recover additional transportation costs. Additional investment in the Trans-Alaska Pipeline System (TAPS) simply reduces the netback to the oil producers at the field. The consumer price impact of using the oil pipeline to carry the butane would only be felt as an increase in any processing and conditioning allowance which might have been allowed by the Commission to cover the $30 million extra investment required for the processing and conditioning plant.

41/ Future gas volumes made available for shipment could have less NGL's content than the Prudhoe Bay accumulation, in which case the "drier" composite gas stream would have more capacity for Prudhoe Bay NGL's without increasing system operating pressure.

The investment requirement not touched on in the preceding discussion is that which might be required for vapor recovery systems on storage tanks in areas where the higher vapor pressure caused by adding butane to the North Slope crude would cause unacceptable air pollution problems. Such ancillary investment requirements highlight the importance of the gas pipeline system design question for the North Slope gas producers, as well as for the gas pipeline project sponsors, and the degree of interest the producers should have in optimizing the design of all facilities involved in producing and transporting Prudhoe Bay hydrocarbon resources.

VII. REQUIREMENTS FOR RESOLUTION

I believe that the Decision creates a predisposition that the 1260-psig system is the one authorized by the President and the Congress by its reference to "the facilities...included in the revised Alcan filing submitted to the Federal Power Commission (FPC) on March 8, 1977."42/ Additional NGL's carrying capability of a higher pressure system might be a desirable feature, all other things being equal. However, a technical report filed with the State of Alaska by the major interest owners in the Prudhoe Bay Field (Arco, BP, Exxon and Sohio) in support of their proposed reservoir management plan states:

> Gas pipeline specifications are not currently known and final specifications may increase or decrease the volume of liquids which must be extracted from the gas to prevent condensation in the pipeline. Regardless of the final gas conditioning requirements, all liquids extracted will be used without waste, either to displace fuel gas or to be transported through the oil pipeline.43/

I believe that the language in the Report accompanying the Decision suggesting that:

> ...Alcan should consider increasing the operating pressure and wall thickness of its 48-inch diameter pipeline in order to allow for more efficient increases in throughput rate for additional reserves which might be committed to the system from either Alaska or Canadian sources...."44/

would make the predisposition a rebuttable one on appropriate showings in a final authorization proceeding for these facilities. The discussion below highlights the principal factors which should be evaluated in such proceeding, should one be required to fix this parameter. I believe that favorable findings in all three areas would be required to support a decision to increase the operating pressure of the Alaskan segment.

42/ Decision, op. cit., p. 13.

43/ Exhibit ALA-33 filed in proceedings before FPC, p. 16. Cited in Comments on the "Decision and Report to Congress on the Alaska Natural Gas Transportation System", Federal Energy Regulatory Commission, October, 1977.

44/ Decision, op. cit., p. 193.

1. Concurrence of the Canadian Government

The Government of Canada, across whose territory some length of any of the 48-inch alternatives would have to pass,45/ has previously expressed severe reservations about the 1680-psig alternative on safety and reliability grounds. The Canadian project sponsors share those reservations. The U.S. project sponsors, while concerned about safety and reliability problems (particularly those associated with proximity to the Alyeska oil pipeline), are primarily concerned that uncertainties associated with the 1680-psig system would create significantly higher risks of construction delay and cost overrun than the 1260-psig alternative.

45/ On February 17, 1978, the Canadian National Energy Board chose a large-diameter (56-inch) alternative for the segment of the system through which both Canadian and U.S. gas volumes will flow, to be installed between Whitehorse, in the Yukon Territory, and the bifurcation point near James River in Alberta. Although the operating pressure of the 56-inch system will be 1080 psig, its NGL's carrying capacity is not less than that of a 1680-psig system installed farther north. The reason is the difference in operating temperature: the 56-inch system will operate at a minimum of 40°F, while the northern portions of the system will have to be chilled to below the freezing point of water (32°F) to avoid thaw settlement problems in permafrost soils.

Permafrost soils, and consequently the need for operating the pipeline at or below 32°F, extend less than 100 miles into Canada. The operating temperature can be increased south of that point, allowing the operating pressure to be gradually lowered without losing significant NGL's carrying capacity. The 1080-psig system is, however, incompatible with the very high pressure (2150 psig) system advocated at one point by Exxon.

Thus, Canada would have to approve the use of a higher pressure system for a short distance from the Alaska/Yukon border if such a system is to be used in Alaska.

The hearing record on the safety and reliability aspects of the 1680-psig system was more extensively developed in Canada than in the U.S. proceedings before the FPC. Accordingly, although U.S. technical representatives continue to believe that the 1680-psig system can be constructed and operated safely and reliably,46/ Canadian authorities still have reservations about the high-pressure alternative based on the evidence presented to them.47/

The U.S. project sponsors have also expressed concern about additional hazards of a higher pressure system because of proximity to the TAPS. The additional potential energy in a higher pressure system is thought to represent more of a threat to the structural integrity of the oil pipeline in the event of a gas pipeline rupture. On the other hand, technical representatives of Exxon, one of the principal owners of TAPS, did not feel there was any significant difference in hazard to the oil pipeline between the 1260-psig and 1680-psig alternatives.

A testing program involving the project sponsors, the owners of the oil pipeline and the Canadian Government would seem to be required prior to any decision to increase the operating pressure of the gas pipeline. Exxon representatives in particular have suggested that the required testing program would not be extensive, but we doubt they have tried to convince the Canadian Government or the Canadian project sponsors, both of whom would have to be satisfied with the testing program and its results before a decision to utilize a higher pressure system could be made.

2. Satisfactory Distribution of Costs and Benefits

In the preceding section, I discussed my concern that consumers might not be the primary beneficiaries of a decision to utilize a higher pressure system for the Alaska segment. Here I suggest briefly what types of analysis would be required to support a conclusion that consumers would benefit from higher pressure.

46/ "U.S. Government Safety and Reliability Evaluation o Different Pipe Size and Pressure Combinations for Alaska Gas Pipeline", Op. Cit.

47/ Their "Statement of Position" has previously been referenced. See page 4.

The first consideration is expectations about throughput volumes which would suggest that lower transportation costs are likely with higher pressure. A positive finding in this area would have to involve not only conclusions about ultimate throughput, but also the timing of throughput increases, as a decision to ask consumers to pay more now in order to pay less later would have to pass a present value test.

The North Slope producers either now have or will have the geophysical and drilling information which might support increased capacity in the delivery system. Much of this information may have been supplied by them to the State of Alaska and the USGS, but under confidentiality arrangements which effectively deny access to any parties not specifically granted permission by the producers. I believe that the burden of proof that a higher capacity system is required is on the producers.

A second consideration is the possibility of a differential tendency to cost overrun between the 1260-psig system and the higher pressure alternatives. As discussed in a previous section, such a tendency would displace upward the throughput volume threshold where a higher pressure alternative has a lower unit cost-of-service than the 1260-psig system. Further studies of the cost overrun problem are currently in progress,48/ and should be available for evaluation in the event that an initial burden of proof regarding volumes available for throughput had been satisfied.

3. Resolution of Extraordinary Financing Problems

I believe that requiring the chosen system to be privately financed is an integral part of an elaborate framework set out in the President's *Decision* to ensure that construction of the selected system is in the public interest. I also feel that it would be inappropriate for the Commission to make any decision which would undermine a component of that framework. I believe that a showing that any extraordinary financing problems associated with choosing a higher pressure system had been resolved would be an essential element in any such choice by the Commission.

48/ For example, the Rand Corporation has been studying this problem applied to coal gasification plants for the Department of Energy.

VIII. RESULTS OF CONFERENCE

An earlier draft of this report was circulated for comment in late September 1978, to the parties with whom we had discussed this matter. The same draft was sent to all parties in Docket No. CP78-123, *et al.*, during November, 1978.

The comments I received indicated a number of corrections to be made which have been incorporated as appropriate but did not alter my basic assessment of the difficulties involved in reaching a determination to increase the operating pressure from the level which had been approved as part of the President's *Decision*.49/

An on-the-record conference of interested parties was held on December 15, 1978. At that conference I presented a proposition, which had been suggested in the comments of the State of Alaska on my draft report, for consideration by the project sponsors and any other interested parties. That proposition was to first construct and operate the pipeline at 1260 psig, and then to increase operating pressure of the pipeline *if* sufficient throughput volumes became available during the operating life of the pipeline to warrant the increase. The State of Alaska suggested that it might be

> ...possible to achieve operating pressures approaching 1440 psig by relaxation of the "design factor" for the pipe Northwest proposes to use from .72 to .8. See 49 CFR 192.111. This would not be a substantial change because the "relaxation" is only to the established Canadian standard. A waiver request would have to be presented to the Office of Pipeline Safety [Department of Transportation] but a good case would be made that safety concerns would be satisfied by the relaxed design factor based on the record in Canada (November 17, 1978, Comments, p. 7)

49/ The U.S. Department of Transportation expressed some concern over perverse incentives inherent in the way natural gas pipeline projects are regulated. I took note of their concerns but advised them that the Commission would likely be unable to resolve them.

The Department of Transportation (DOT) and its Office of Pipeline Safety were represented at my conference. Their representatives were not encouraging about the prospects for a waiver because of the proximity of the pipeline to the haul road which serves the North Slope producing area. DOT safety requirements are more stringent for gas pipelines which operate near highways50/; thus, sufficient relaxation of the standard to accommodate an increase in operating pressure would likely require a double waiver. The DOT representatives advised use of thicker-wall pipe if higher operating pressures were to be attempted.

I closed the conference by requesting that the project sponsors present their views on the operating pressure question in detail to the State of Alaska and the DOT, both of whom appeared to favor a higher capacity system.51/ The sponsors were then to report to the Commission on their views regarding the possibility of increasing the system capacity, and on the results of their discussions of this matter with other interested parties. The sponsors' filing of March 2, 1979, requesting a Commission order finalizing the selection of 1260 psig as the operating pressure for the Alaska segment, is in compliance with my request. A copy of that filing is attached to this report.

50/ Whether the haul road is properly classified as a "highway", and thus imposes the more stringent safety standard on the gas pipeline, is a matter which I believe is still at issue.

51/ Arco representatives, both in their comments on my draft report and in their remarks at my conference, favored increasing the operating pressure but reducing the diameter of the gas pipeline system. Exhibit Z-5, attached to the project sponsors' March 2, 1979, filing, indicates that the operating efficiency characteristics of the 1680-psig, 42-inch system which Arco favors are essentially the same as those for a 1260-psig, 48-inch system.

IX. CONCLUSIONS AND RECOMMENDATIONS

Relevant Considerations

As discussed in section IV above, the primary method of analysis to determine the appropriate throughput capacity for a gas pipeline is the comparison of plots of unit transportation cost vs. throughput volume for alternative system configurations. The project sponsors have attached such plots for the principal alternative systems as Exhibits Z-4 and Z-5 in their filing. Similar computations are also included in section IV of this report.

In my judgement, there are two factors in these comparisons which should be considered:

- The least-cost system at expected levels of throughput, and
- Expectations about the throughput levels for which fuel penalties start to significantly increase the unit transportation cost.

For expected levels of throughput up to 3.3 bcfd, the 1,260-psig system is indicated by the project sponsors' analysis. Although our analysis puts the crossover point from the 1,260-psig system to the 1,440-psig system slightly lower than the project sponsors',52/ our analysis also supports the 1,260-psig system if the expected levels are in the 2.8-to 2.9-bcfd range.

Perhaps more important, in my judgement, is an assessment of the likelihood that throughput levels will exceed the range of efficient operation for the recommended system. For the three systems which appear to be feasible for the Alaska segment--1,260, 1,440 and 1,680 psig systems--there is a considerable range of throughput volumes for which there is probably sufficient uncertainty the capital cost

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52/ Our results put the crossover point at 2.65 to 2.9 bcfd, depending on certain assumptions about capital costs other than for compression. The remainder of the difference between our analysis and Alaskan Northwest's is in the installed cost of compression and chilling facilities.

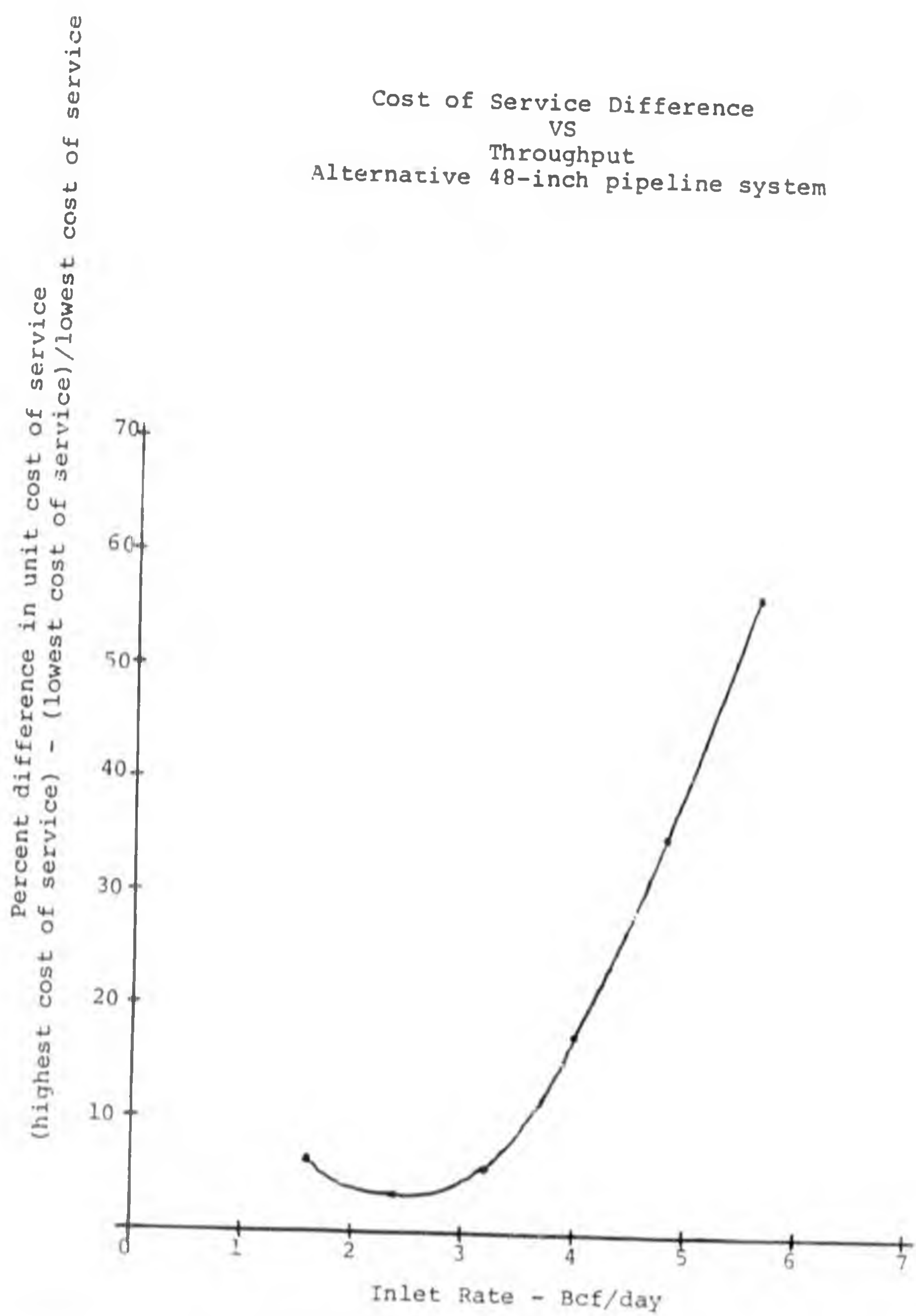
I would caution against assigning undue precision to the exact crossover points from one system to another. The differences between Northwest's capital cost estimates and ours for the 1,680-psig system is $48.3 million, or less than 3 percent of the base 1,260-psig estimate, whereas the expected cost overrun for the 1260 psig case is about 30 percent of that estimate.

estimates upon which the cost of service calculations are based to prevent a definitive conclusion that one will have a lower unit cost of service than another. For example, if I arbitrarily pick a difference of 10 percent between the cost of service of the lowest and highest cost systems for a given throughput level as a difference which is significant, then the unit cost of service for all three systems would be essentially the same from a throughput of about 2.6 bcfd to almost 4.0 bcfd, according to Alaskan Northwest's Exhibit Z-4. Above 4.0 bcfd and below 2.6 bcfd, the three curves diverge more rapidly.

Our computations in section IV illustrate better the divergence of the "J-Curves" at higher throughput volumes because we have plotted them for a larger range of throughput. On the next page, I have used the data from my Figure 1 to plot the difference between the lowest and highest cost systems as a percent of the lowest cost system for various levels of throughput. Notice that because of differences in our respective capital cost figures, our 10-percent difference point is closer to 3.5 bcfd than Alaskan Northwest's 4.0 bcfd. However, the plot illustrates that, although the differences are small over a range of throughput, they increase rapidly as the upper end of the range of efficient operation for the 1,260-psig system is approached.

In section VII of this report, I discussed the difficult problems which would have to be resolved to reach a determination to increase the operating pressure of the Alaskan segment. I believe that the Commission need not address these problems unless there is a significant change in expectations about gas volumes available from the producing areas to be served by the ANGTS. In view of the difficulties discussed in my report and in view of the relatively small differences in unit costs of service over the range of at least 2.6 to 3.5 bcfd, I would recommend that you reaffirm the 1,260-psig system for the Alaskan segment unless you are provided with new information which demonstrates that there is a significant probability of volumes in excess of 4.0 bcfd in the area to be served by the ANGTS.

Cost of Service Difference
VS
Throughput
Alternative 48-inch pipeline system



Status of Information

The information available at the time of the Decision, the results of the extensive analysis by the FPC and the July 1, 1977, Report to the President of the Working Group on Supply, Demand and Energy Policy Impacts of Alaska Gas, are cited in the project sponsors' filing. They cite the relevant conclusion in the Decision as the following:

> Peak-day capacity utilizing nine compressor stations will be 2.6 bcfd, with an average daily volume of 2.4 bcfd. By installation of intermediate compressor stations, the system could be increased to 3.4 bcfd peak capacity, with an average day capacity of 3.2 bcfd. The system capacity could be further increased by addition to the compressor horsepower at each station. (Decision, p. 17.)

I also note in the report accompanying the Decision the following passage:

> The routing of the Alcan system provides future access to reserves which might be discovered in the Beaufort Sea or elsewhere on the North Slope. Alcan similarly could transport gas from other areas of Alaska or even from the Gulf of Alaska by means of somewhat longer supply laterals. Further, the Agreement with Canada provides for the use by Canada of the Alcan main line at a throughput up to 1.2 bcfd. Therefore, redesign of the system to enable inexpensive expansibility up to 3.9 to 4.0 bcfd south of Whitehorse, Yukon Territory, is essential. (Decision, p. 196.)

I infer from this passage that the throughput volume anticipated at that time from sources in Alaska which might be connected to the ANGTS was in the range of 2.7 to 2.8 bcfd (3.9 to 4.0 bcfd less 1.2 bcfd).

Interestingly, the principal concern about throughput volume at the time of Congressional consideration of the Decision was that Prudhoe Bay Field production might not come up to expectations, and thus the system selected by the President might be too large for the available volumes. 53/ Some perspective on the possibility that available volumes will be either higher or lower than expected was provided to us in the course of this inquiry by the State of Alaska. As both a royalty owner and the conservation authority for the primary prospective areas on the North Slope, the State's information on these areas must be presumed to be as complete as anyone's. I have reproduced on the next two pages a series of tables of expected reserves and deliverability, along with a map of the area covered by the estimates. As you can see from the tables, the estimated probability that available throughput volumes will be 4.2 bcfd is about the same as the probability that throughput will be only 2.0 bcfd. I don't see any basis in this information for changing from the 1260 psig system.

The CO_2 Standard

A matter which I feel ought to be considered further is the CO_2 standard for gas delivered to the pipeline. I mentioned above (p. 22) that the Parsons study recommends further study of possible alternative specifications for CO_2 content and gas pipeline pressure. Increasing the system operating pressure is difficult for all the reasons discussed above, but I believe changing the CO_2 specification is separable and should be considered. The potential benefits to be derived from transporting more CO_2 include reduced conditioning costs, increased capacity for transporting NGL's, and possibly increased availability of NGL's (particularly propane) due to reduced fuel requirements of a less intensive processing and conditioning plant operation. The State of Alaska and Arco 54/ raised the CO_2 issue in comments

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53/ See the very extensive discussions of this matter during the Senate consideration of the Decision. Hearings before the Committee on Energy and Natural Resources, United States Senate, on S.J. Res. 82, Joint Resolution to Approve the Presidential Decision on an Alaska Natural Gas Transportation System, September 26, 27, October 11, 12 and 25, 1977. Publication No. 95-73.

54/ "Comments of the State of Alaska on the Design Specifications and Initial System Capacity of the Alaskan Segment of the Alaska Highway Pipeline Project", and "Motion of Atlantic Richfield Company for Clarification," both filed in Alaska Northwest Natural Gas Transportation Company, Docket No. CP78-123, et. al. on April 5, 1979.

North Slope
Original Gas In Place
Trillion Cubic Feet

	Confidence Level		
	95	50	5
Prudhoe Bay	←	40.4	→
All Other	0.5	13.4	30.5

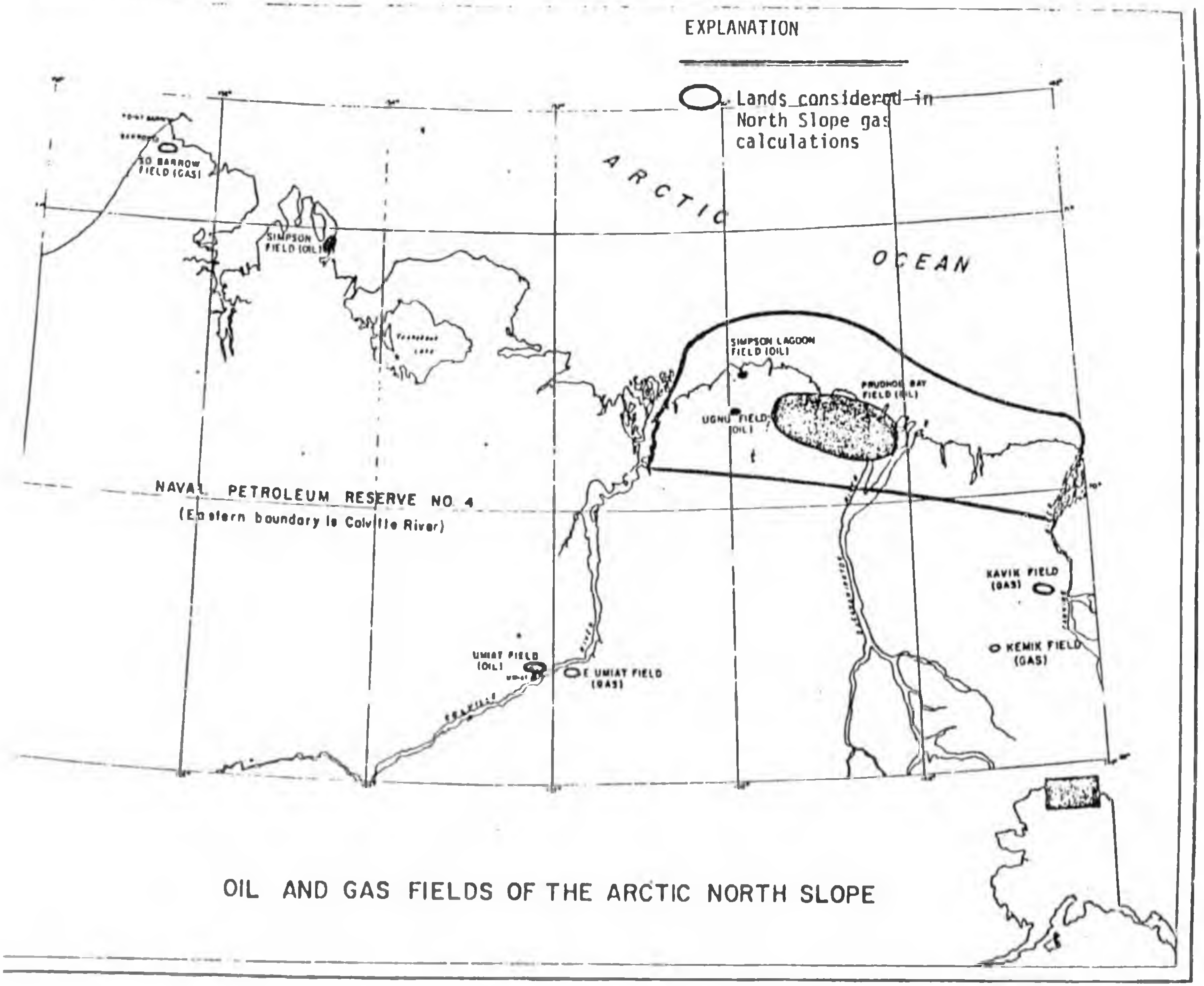
Recoverable Reserves *
Trillion Cubic Feet

	Confidence Level		
	95	50	5
Prudhoe Bay	←	21.0	→
All Other	0.3	8.0	18.3

Deliverability
Billion Cubic Feet Per Day

	Confidence Level		
	95	50	5
Mid 1984			
Prudhoe Bay	1.5	2.0	2.5
All Other	0	0.3	0.5
Mid 1988 and Beyond			
Prudhoe Bay	1.5	2.0	2.5
All Other	0.5	0.8	1.7

* takes into account recovery factor, gas conditioning and fuel useage.



OIL AND GAS FIELDS OF THE ARCTIC NORTH SLOPE on the project sponsors' March 2, 1979 filing regarding system operating pressure. Sohio 55/ has raised the subject of standards for "pipeline quality gas" in the Commission's omnibus rulemaking proceeding on tariff and rate of return issues in Docket No. RM78-12.

The North Slope producers and the State of Alaska have an additional interest in this matter because of the impact of butane blending on the vapor pressure of North Slope crude. Exxon had furnished the plot of vapor pressure vs. temperature for North Slope crude containing various amounts of NGL's which appears on the following page. I have superimposed on that plot the approximate temperature range at which wax formation starts to be a problem with the North Slope crude, and the vapor pressure standard for air pollution control in Southern California.

Wax formation limits the use of cooling as a technique for vapor pressure control. If cooling cannot be used, then vapor recovery systems must be installed on storage facilities to control emissions. Addition of any butane at all to the crude stream moves the vapor pressure at a given temperature from curve 2 toward curves 3 and 4. Because of the temperature limit imposed by wax formation, addition of any butane at all increases the likelihood that vapor recovery systems will be required, particularly if the vapor pressure standard is made more stringent. Thus, the North Slope producers have an interest in the CO_2 standard not only because of its impact on the cost of the conditioning facility, but also because of its impact on the capacity of the sales gas stream to transport NGL's, particularly butane.

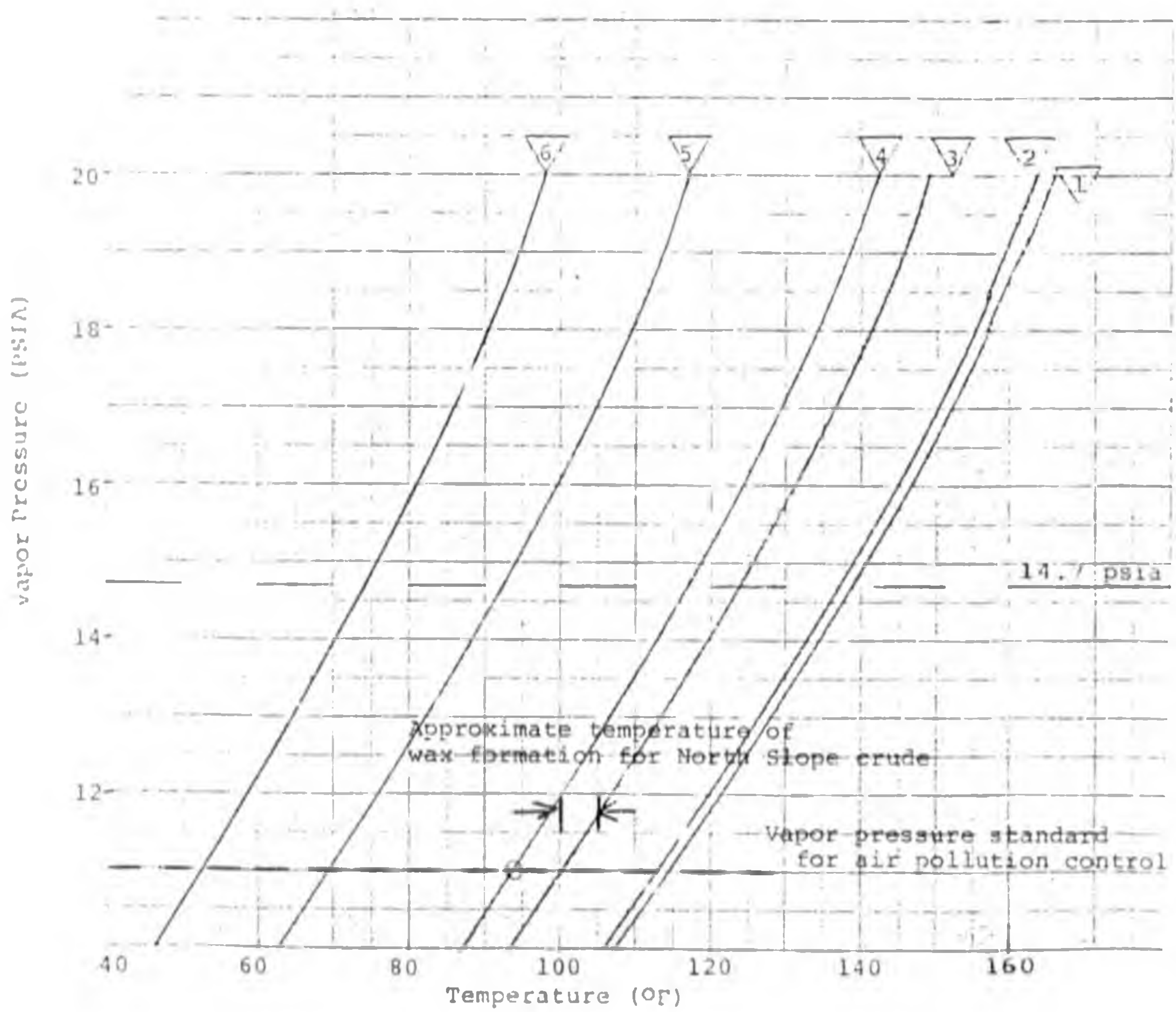
Increasing the CO_2 content of the gas stream may be cost-effective for the consumer also. Without pre-judging how additional NGL's might be charged for transportation through the ANGTS, i.e., whether transportation charges would be on a cents per mmBtu basis or on some other basis, transportation of more of the Prudhoe Bay hydrocarbon reserve through the ANGTS offers the prospect of increased utilization of the facility, and, hence, lower overall costs to consumers.

55/ "Comments of Sohio Natural Resources Company on Notice of Proposed Rulemaking Issued April 6, 1979", filed in Determination of Incentive Rate of Return, Tariff and Related Issues, Docket No. RM78-12, on May 7, 1979.

FIGURE 1

PRUDHOE BAY CRUDE + NGL VAPOR PRESSURE

Bbl.NGL/Bbl.Crude		Mixture
0	1	Crude
.0154	2	Crude + iC5+
.0301	3	Crude + NC4+
.0367	4	Crude + iC4+
.0470	5	Crude + 25% C3, iC4+
.0573	6	Crude + 50% C3, iC4+



Increasing the CO_2 content of the sales gas stream would have the effect of shifting to consumers certain costs of processing and conditioning the Prudhoe Bay gas, an outcome which the Commission has expressed its intention to prohibit with its proposed policy regarding the recovery of certain "production-related" costs as defined in the Natural Gas Policy Act. 56/ However, it is possible that some cost-shifting through relaxation of the CO_2 standard would be the optimal solution for the overall conditioning and gas transmission system.

Increasing the CO_2 content of the sales gas stream would pre-empt some of the ANGTS throughput capacity, but additional processing and conditioning facilities could be installed to remove the extra CO_2 if the additional capacity were required. This could be done without any loss of NGL's carrying capability if incremental volumes of natural gas have a lower NGL's content than the Prudhoe Bay gas.

The State of Alaska and Arco, in their above referenced comments on Alaskan Northwest's March 2 filing, have requested a Commission statement regarding the appropriate proceeding for resolution of the CO_2 content issue. I believe this issue is separable from the throughput capacity issue, because any capacity committed to CO_2 transportation when operations begin can be retrieved by installation of additional conditioning facilities if sufficient quantities of natural gas become available to require that capacity. Thus, I believe that the maximum allowable operating pressure question should be resolved independent of the CO_2 question, the latter being better addressed in RM78-12, wherein the Commission is considering the project company tariffs, or perhaps as an ancillary issue in RM79-19, regarding the responsibility for production-related costs. It is the former proceeding in which the issue of appropriate standards for "pipeline quality gas" seems to me to be most directly before the Commission.

56/ See the Commission's Notice of Proposed Rulemaking in RM79-19, February 2, 1979.