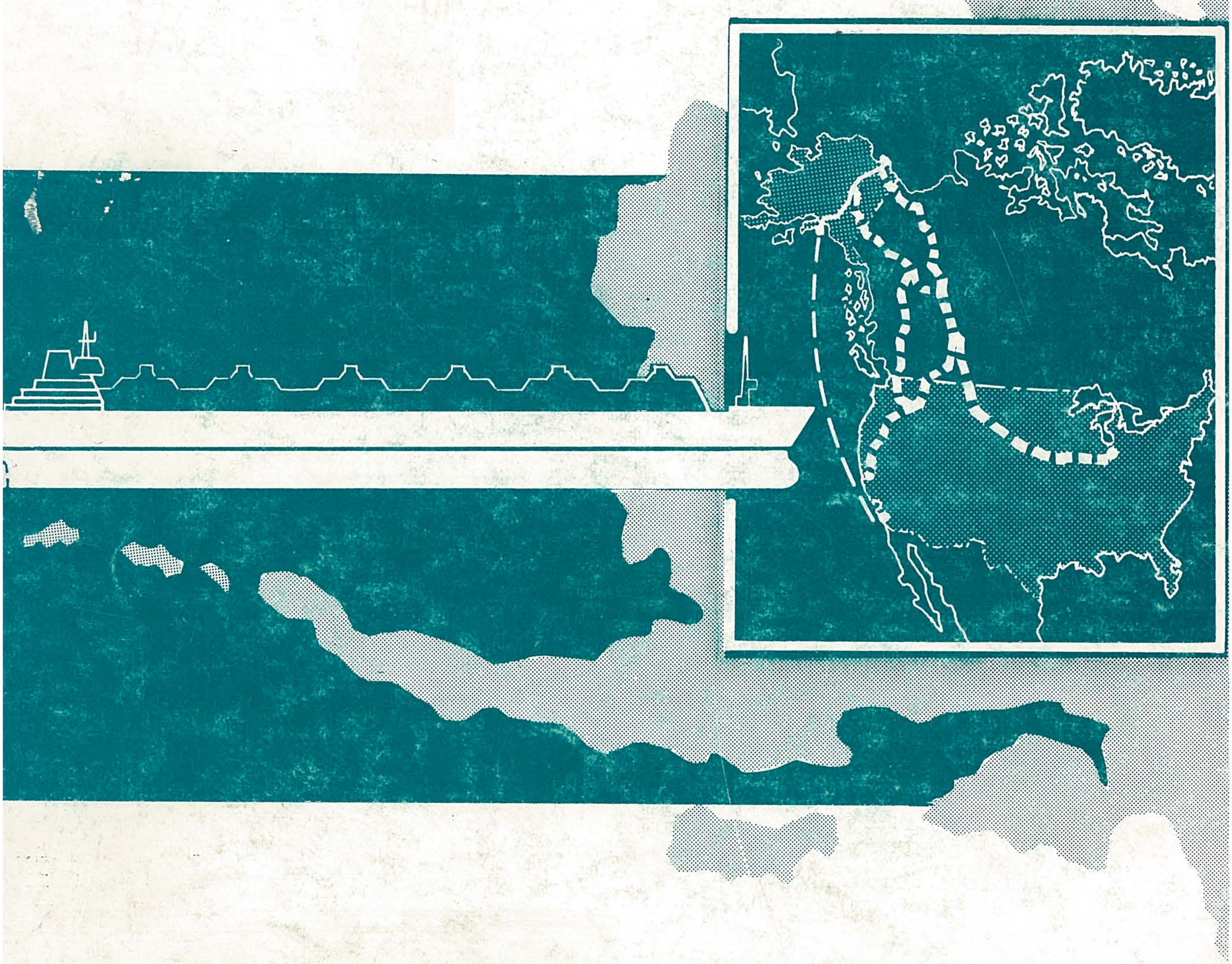
EL PASO ALASKA COMPANY
DOCKET NO. CP 75 - 96, ET AL.

INITIAL DECISION ON PROPOSED ALASKA NATURAL GAS TRANSPORTATION SYSTEMS



UNITED STATES OF AMERICA

FEDERAL POWER COMMISSION

FEBRUARY 1, 1977

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El Paso Alaska Company, et al.) Docket No. CP75-96, et al.

INITIAL DECISION ON COMPETING APPLICATIONS FOR AN ALASKAN NATURAL GAS TRANSPORTATION PROJECT

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PREFACE

In 1968 a significant discovery of hydrocarbons consisting of roughly 19 billion barrels of oil and 26 trillion cubic feet of natural gas was made at Prudhoe Bay, Alaska. By lease sales held in 1968-1969, the State of Alaska sold the basic leases for about $900 million, reserving for itself a 12.5% royalty interest. Development of the Prudhoe Bay field and plans for an oil pipeline commenced almost immediately. This field, which holds the largest discovered gas reserve on the North American continent, represents roughly 10% of proven 1975 U.S. natural gas reserves and more than a year's supply for all U.S. consumers.

Coeval with plans to develop the Prudhoe Bay field and transport the oil, several companies commenced studies to move the natural gas to markets in the lower 48 states. The first formal proposal to emerge and to be filed with the Commission in March 1974 was from the Arctic Gas Study Group, primarily a consortium of American and Canadian natural gas pipeline companies (although the original group also included the principal producers). 1/ This group, Arctic Gas, proposes an overland pipeline route extending east from Prudhoe Bay, crossing the Alaskan Wildlife Range and the Mackenzie River Valley, then south through Alberta to the U.S., entering at two points, one on the British Columbia-Idaho border and the other on the Alberta-Montana border. Distribution in the U.S. will be through an eastern leg by the Northern Border group to Dwight, Illinois, and a western leg via Pacific Gas Transmission Company to west coast states. This pipeline is also designed to transport Canadian Mackenzie Delta gas and future Beaufort Sea gas to Canadian markets. A summary statement of the various applications is set out in Appendix A hereto. See, also, the attached map, Ex. AA-146, admitted as a late filed exhibit.

In September 1974, a second system was formally proposed by the El Paso Alaska Company (El Paso). It would move only Alaskan gas by pipeline across Alaska to a liquefaction plant at a warm water port at Gravina Point on Prince William Sound, Alaska, then by a fleet of liquefied natural gas (LNG) tankers to a California

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1/ As finally constituted, this group includes four principal pipeline applicants--Alaskan Arctic, Canadian Arctic (an applicant before the National Energy Board of Canada), Northern Border (a partnership of six natural gas pipeline companies), and Pacific Gas Transmission Co.

terminal and regasification plant to be operated by Western LNG Company (Western LNG), and then by pipeline and through displacement procedures to other natural gas companies throughout the United States. 1/ No transportation of Canadian Mackenzie Delta gas is contemplated. A summary statement of these applications also appears in Appendix A hereto.

In July of 1976 Alcan Pipeline Company filed a third competitive application, seeking certification of a route across Alaska to Fairbanks, Alaska, then along the Alcan Highway to the Alaska-Yukon border, then through Canada along the Yukon-British Columbia border, then south utilizing in part some existing Canadian gas lines in British Columbia and Alberta, and then to the U.S. border, connecting in the west with Northwest Pipeline near Sumas, Washington and PGT at Kingsgate, B.C., and in the east with facilities to be constructed by the Northern Border group at Monchy, Saskatchawan. This application assumes Northern Border, an applicant in the Arctic Gas project, would distribute gas in the midwest and east. A summary statement of Alcan's application is also set forth in Appendix A.

As an adjunct to the applications here, one must also consider the Foothills proposal before the NEB to move Mackenzie Delta gas to Canadian markets through the so-called "Maple Leaf Project."

The description of the applications set forth in Appendix A is not intended to make findings disposing of disputed issues but represents only a declaratory statement of what the parties seek. The gas volumes used are pro forma only.

Pursuant to the Commission's order of January 23, 1975, the hearing process commenced with a prehearing conference held on April 7, 1975. 2/ Hearings commenced on May 5, 1976, and essentially have continued almost uninterrupted since that time. A consolidated hearing also was held on the limited issue of west coast LNG plant siting with the Pacific Indonesia case (Docket No. CP74-160).

1/ Displacement is a method of distribution whereby natural gas may be supplied from a closer point in exchange for gas elsewhere. At its optimum, it avoids physically transferring gas between markets.

2/ Appendix B hereto sets forth the Commission's orders permitting interventions Roughly half the States, most of the U.S. natural gas pipelines, and a plethora of prospective purchasers and other interested parties intervened.

A restricted service list voluntarily was established for the purpose of limiting distribution of materials used in the hearing to those actively participating in the hearing process. Parties not on the list were provided material only on request.

No one disputes that these applications, including the staff recommended "Fairbanks alternative" overland route, are mutually exclusive: a grant of any route to any applicant would preclude a grant to another. The present level of discovered gas reserves will justify only one transportation system, and the billions of dollars of capital costs for initial construction are simply so high that it would be cheaper in the foreseeable future to add to an existing line rather than to commence another.

The magnitude of the physical undertaking and cost of building a gas transportation system from Alaska apparently exceeds any prior U.S. private undertaking. The estimated $8-$11 billion costs are such that the resolve to go forward will require a financial commitment over the construction period of a substantial amount of that funding normally available to all utilities. Even if there is no miscalculation in the projected level of funds necessary to complete the project, the volume of both debt and equity capital required may drive up the cost of other utility borrowing by "crowding out" the availability of market money for that purpose. Similarly, marketability of the gas is such that a substantial miscalculation in costs could result either in serious impairment in the demand for Alaska gas in the market place or force a large segment of the consuming public to guarantee prices in excess of available alternative energy costs. Unfortunately, definitive values to be placed on these considerations cannot be given; the values shift with our own perceptions of the need for energy, our evaluation of this country's ability to conserve energy or at least limit its growth, the availability of alternative fuels, and the economic, social, environmental and political costs of bringing other fuels to market.

A. The Record

The record closed on November 12, 1976. It consists of 253 volumes of transcript, embracing almost 45,000 pages, about 1,000 exhibits (some such as the environmental impact statements being almost 1,000 pages each), and innumerable items by reference.

Throughout the hearing, an effort was made to require the parties to brief issues which appeared to be sufficiently discrete that they could be easily segregated. 1/ Thus, for example, briefs were submitted early on in such areas as the description of the applications and proposed conditions, financial plans and tariffs, LNG liquefaction plant siting, LNG regasification plant siting, the PGT proposal to construct a western leg on the Arctic Gas system, geotechnical, Canadian law and treaty, and gas reserves. These were staggered over the late summer and into the fall. Other areas that were susceptible to such treatment (e.g., net national economic benefits, socio-economic, and general environment) were not separately briefed early because of the late announcement and application of the Alcan proposal and the inability of the Federal Power Commission environmental staff to file its Environmental Impact Statement on that proposal until mid-September. A number of issues, therefore, were dealt with initially directly from the record and were revised on the basis of arguments made by counsel on brief. Others, where the briefs contained the positions of the parties, could not be fully addressed until after the close of the hearing. All arguments of all parties on all issues have been considered, and the fact that some briefs on some issues were not filed until late has not resulted in any inability to address the position of the parties on those facts marshalled to support their arguments.

1/ 1. Applications and proposed conditions
2. Western LNG plant siting
3. El Paso plant siting
4. Arctic Gas western-leg proposal
5. Gas supply
6. Environment
7. Geotechnical
8. Canadian law and treaty
9. Allocation: U.S., Canadian
10. Economics (construction, scheduling, capital costs, cost of service)
11. Tariff
11(a) Mock-up tariff exhibits AA-133, AP-16, EP-276
12. Socio-Economic
13. Net national economic benefit
14. Position of parties other than applicants to all issues
15. Financing
16. Eminent domain
17. Wrap-up on all issues (10-page limit)

Also, while it has usually been the Presiding Judge's practice to strike transcript page references from the final draft of the decision, the needs of the parties to manage this massive record on short exception schedules dictate that such references remain. A disclaimer is entered, however, on two counts: first, since time has not permitted the final decision to be checked in all instances against the record, there are certain to be errors in transcription, and, secondly, a reference does not mean that the page cited is the only or even necessarily the best reference for the fact cited.

B. Official View

An official view was made in August 1976 of the sites of the proposed major facilities and pipeline routes of all three applicants. A statement of the itinerary, participants, and general observations of what was viewed was served by the Presiding Judge on September 3, 1976. A nettlesome problem immediately arose thereafter because the view not only gave an impression of the physical aspects of the area to be traversed and the sites, but observation of the area also led to impressions as to the weight to be afforded some of the evidence which, on its face, was inconsistent with what was seen. Caribou grazing on fields surrounded by gravel roads, pipes carrying oil to the pump stations, and oil field construction and industrial facilities gives a different impression of the compatibility of some caribou with industrial areas than the record might have indicated. 1/ Similarly, an eagle's nest with fledgling birds just a few feet from the Alyeska main road to the Valdez oil terminal under construction gives a strong impression of at least one set of eagles' sensitivity to man's activities.

A "view," moreover, is not held in a vacuum and the people accompanying those viewing are required to identify and describe what is being seen--whether it be to state that a particular bird seen at Demarcation Bay is a ptarmigan or that an animal seen denning next to a gravel road at Prudhoe Bay is an Arctic fox. Nor can one ignore that a question as to revegetation efforts next to the hovercraft road at the Yukon river crossing near the present bridge

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1/ One of the caribou observed from the tour bus at Prudhoe Bay clambered onto the road a few feet in front of the bus when the bus stopped, crossed in front of the bus, and went to another field on the other side of the gravel road.

or a question as to where snow roads had been built (having melted by August) the past winter will elicit an answer which may go beyond the mere statement of mileposts or merely pointing to the revegetation. Observations which might affect the weight to be accorded testimony of record were set forth in the Report of the Official View in order to give the parties an opportunity to evaluate the material.

C. Lack of Producer Sales Contracts

In addition to being burdened by their gargantuan size and financial requirements, some aspects of each proposal represent either a scaling-up of facilities from current commercial levels (Gravina Point LNG plant and the LNG ships) or a process which may be at the frontier of the state of the art of construction techniques (e.g., high pressure, 1250 psig and up, buried chilled pipelines or snow road construction). But these impediments pale when compared to those problems caused throughout the entire period of the hearing by the failure of those owning the reserves to enter into sales contracts--principally the State of Alaska; Atlantic Richfield Company; Exxon Company, U.S.A.; and Sohio Petroleum Company.1/ This refusal, by itself, has prevented the expeditious and orderly examination of sizing of the pipeline, financing, marketability, and a host of related matters, including disputes as to which companies ultimately would buy the gas. Only on the last day of hearing, November 12, 1976, did the State announce sales of its royalty gas to El Paso Natural Gas Company, Southern Natural Gas Company, and Tenneco Alaskan, Inc. But even these contracts for the royalty gas are not effective until ratification by the State legislature, which is not in session.

The Commission, with certain misgivings, set these proceedings for hearings absent sales agreements because the national interest demanded expedition. Upon the commencement of the hearings in May 1975, a running dialogue was instituted with the State of Alaska and producers seeking, inter alia, to ease them to a position where they might perceive that their best interests coincided with the national interest to have contracts for sale submitted at the earliest time during the pending hearings. This effort was singularly unsuccessful insofar as sales agreements were concerned, although some progress was made in at least getting the Producer to discuss these matters on the record. Their continued recalcitrance was the subject of several progress reports to the Commission, and it became apparent that, on a de facto basis, the Commission would

1/ There is still operative a preliminary agreement giving Columbia Gas a future purchase right to Sohio's Prudhoe Bay net gas reserves, subject to agreement on price and other terms. The gas volume covered by this agreement is presently uncertain, since it depends on a BP Alaska net profits royalty interest in Sohio's reserves which, in turn, depends on the level of 1977 Prudhoe Bay oil production (Sohio letter of August 27, 1976, to Presiding Judge, 263/36,935).

not insist on compliance with the general Commission requirement that the sales agreements be on file before this phase of the application is completed (see, e.g., Reports of January 21, 1976, April 27, 1976 and June 11, 1976).

It also became apparent that unless the producers sell their natural gas reserves at or about the time that a decision otherwise was reached on the preferred route, the financing necessary to building the line could not take place no matter what the Commission authorized.

The producers have in fact specified those conditions which, if met, would induce them to sell their reserves. These demands, basically unyielding, are directed to both the Commission and Congress ---- seeking in the main the prior establishment of a sale price, a disclaimer of vintage pricing, 1/ and a reversal of Commission policies interpreted by the producers as requiring that they guarantee future minimum delivery volumes regardless of field production capability. 2/

As recently as September 30, 1976, the producers refused to state categorily that they would enter into contracts to sell the gas upon the certification of a prime pipeline route, although they have broadly hinted at how reasonable they will be and how they would act responsively in the public interest. Their position is that they are in business to sell hydrocarbons and the only question is timing. It is timing of the sales agreements, or lack thereof, of course which has burdened this record. Thus, while stating their concern for the national interest and the requirements of this country for energy at an early date, their prime consideration for early sale turns on other more parochial interests. The only conclusion possible from their actions is that the national interest to ARCO, Exxon, Sohio, etc. lies somewhere below their own

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1/ A method whereby gas sold at different periods is priced separately.

2/ Substantial effort was made to see if it would be possible for contracts to be fashioned which would protect the producers from pitfalls that they considered inherent in early sales. These failed, probably because any sales agreement, no matter how conditioned, could fix a date used by the Commission or Congress for vintaging.

economic interest, or at least, the national interest of the U.S. appears to them as negotiable in their bid to obtain certain concessions from the Commission or the Congress in return for their cooperation in bringing this gas to market. 1/ Admittedly, the uncertainty of regulation is not as bankable as the 3/4 billion dollars ARCO, for example, had negotiated as advance payments by prospective Alaskan gas purchasers before the Commission found such payments against the public interest. But it shows that the producers, like G.B. Shaw's dinnertime companion, have a price at which they would sell their "service," and all of their protestations to the contrary cannot hide that they are mainly dickering over price. The record, unfortunately, now stands with no firm commitment on the part of any producers to sell natural gas, or even that they will agree to sell it immediately upon tentative certification of a successful applicant.

The State of Alaska's role as a royalty owner, taxing agent, and conservator of its resources is also at issue. The State of Alaska embarked early on upon a course designed to maximize the economic benefits flowing to Alaska from its hydrocarbon resources. This laudable goal for Alaskans, unfortunately, is not always consistent with the general public interest of all of the people of the United States. It may portend, again unfortunately, a confrontation on the merits of an indirect transfer of payments from other parts of the country to Alaska through excessive payments for Alaskan hydrocarbons. These are not easy questions: the State's demands were not crudely put nor outrageous on their face. The difficulty is that they are also not always obvious, and it is not easy to gain a clear picture of the State's demands or whether those who deal with the State privately are in a position to bargain effectively for the public interest. Any Prudhoe Bay field operating plan must be sanctioned by the State, and the producers may, for example, agree to conditions in the field production arrangements which could be quite detrimental to long-term consistent sales of interstate gas.

In addition to the lack of sales agreements, there is still no approved production agreement for oil or gas from the Prudhoe Bay Field. A draft agreement was presented to the parties for the first time on August 18, 1976, some 7 or 8 months after it was first suggested it might be filed. It will be several months still until

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1/ The reasons why the Commission may not have, as yet, set a price for Prudhoe Bay gas are (1) that the producers and the State have not definitively stated how much gas will be produced and on what schedule, and (2) no one has formally requested that a rate be set.

State approval will be given. A summary of the producers' technical report on the proposed operating plan is attached as Appendix C hereto. It is generally accepted, although Alcan does not agree, that in all likelihood 2 to 2.5 Bcfd of gas will be produced 5 years after the decision is reached to build the gas conditioning plant. But, absent State approval, deliverability remains an "unknown." (See Gas Supply discussion infra From the start of the hearing, the State took the position that it could not force the producers to submit an agreement. The producers' refrain was that they were not ready, bolstered occasionally by suggestions that they were not prepared to resolve ticklish problems on the fixing of their respective ownership interests in the reserves and that the production agreement delay was tied into that problem.

The net result of the lack of sales contracts and lack of an approved field production agreement is that the record has been closed without a deliverability schedule of gas which will be sold and without knowing the purchasers of this gas. The record has been closed without knowing more than the alleged general cost of field gathering and gas conditioning facilities or who would pay for them. The record has been closed without specific estimates of reserves on the Lisburne and Kuparuk formations which are part of the Prudhoe Bay Field. (See Gas Supply section, infra). These record deficiencies in the usual case would require that the entire proceeding be held in abeyance pending their resolution. Here an overwhelming consensus on the part of the Commission, the Congress and the Executive Branch has been to go forward anyway and to pick a pipeline. It is not the best way to make rational decisions.

Given the above considerations, it is amazing in fact that this proceeding progressed so far so fast. The applications were filed prematurely from any rational regulatory point of view, and the Commission's determination to try the cases without an essential ingredient represents a regulatory boldness normally not seen. Nor was this the only area where forces beyond the Commission's control dictated procedural requirements which complicated the hearing schedule. The Congressional deliberation on the Alaska Natural Gas Transportation Act of 1976 (see succeeding section) essentially dictated consideration of the Alcan proposal--applications filed almost 2½ years after Arctic Gas filed its application, 15 months after the hearing commenced, and within a few weeks of the then-scheduled close of the hearing. Materials filed before the Commission were subject to surfacing again before the Congress, other Federal agencies, and the Canadian government and Canadian National Energy Board. No party could afford to leave any inference in this record unanswered, for fear it would be used elsewhere, even where, from an evidentiary point of view, it might believe that the Commission would not rely upon it. While at times it appeared to the Presiding Judge that the parties wished to leave no grain of sand unturned in their quest for "truth," the fact of the matter is that this voluminous record contains little material not both relevant and necessary to the interest of the parties and the public.

D. Marketability

It must also be recognized at the outset that the marketability of North Slope gas in the lower 48 states several years in the future cannot now be determined with full assurance. One must consider unanticipated cost overruns for the construction of a transportation system, to which must be added the presently unknown price of gas in the field and gas gathering and conditioning costs. The actual total delivered cost in the market place could reach a level which prospective consumers would find unattractive, when compared with the then-current costs of alternative energy supplies. Such alternative energy costs will depend, in part, on U.S. regulatory and national energy policy determinations over the intervening years and on the intervening price movement in international fuel supplies, principally imported oil (see infra).

E. The Alaska Natural Gas Transportation Act of 1976

Throughout 1975 and 1976 the Congress of the United States studied the efficacy of passage of a statute to govern the ultimate certification of these applications through (1) involvement of the Executive and Legislative Branches in the review procedure and (2) a concommitant limitation on judicial review. The Alaska Natural Gas Transportation Act of 1976 (Alaska Act) was passed unanimously by the Congress on September 30, 1976, and signed into law on October 22, 1976 (15 U.S. 719, 90 Stat 2903; attached hereto as Appendix D with a portion of the legislature history). The Commission has not yet suspended the proceeding pursuant to procedures provided by Section 5(a)(1) of the statute.1/ Thus, the Administrative Procedure Act still applies, and its requirements have been met; this initial decision is entered pursuant to the APA and the Natural Gas Act.

1/ By order issued December 13, 1976, proceedings under the Natural Gas Act will be suspended on February 1, 1976, or on such earlier date as this initial decision issues.

The statute requires that the Commission and the President discuss a number of considerations which are not usually required in a certificate case. To the extent the evidence permits, they will be discussed in the initial decision. The statute also proscribes certain regulatory options, such as denying equal access tc pipeline capacity and prohibiting of the right of Alaska to "withdraw" gas for intrastate use after an interstate sale. These too are discussed in the context of the ability to finance these projects and their affect on costs.

II

JURISDICTION

The Commission's jurisdiction under the Natural Gas Act over activities and transactions from the wellhead to the lower-48 distributors is imperfect regardless of which Alaskan gas project is authorized.

To begin with, respecting wellhead sales in Alaska, jurisdiction is unquestioned only as to interstate sales by the corporate producers. The State of Alaska resolutely denies federal jurisdiction over its interstate sales. Transportation through Canada by Arctic Gas or Alcan would be subject to regulation by the Canadian National Energy Board, although its standards for rate regulation are generally comparable to those of the FPC, and the ad referendum treaty (Appendix H, Part III) provides for equitable allocation of costs between U.S. and Canadian consumers (see infra Canadian Law section). Transportation of LNG by ocean-going vessels, as proposed by El Paso, has been held by the Commission as not subject to direct regulation.1/ In sum, producer wellhead sales in interstate commerce, transportation of those volumes within Alaska, and interstate transportation and sale of Alaskan gas within the lower-48 states to distribution companies are the only aspects common to all three projects which are fully subject to Commission jurisdiction.

While the Commission lacks direct jurisdiction over transportation in Canada or by ocean carrier and may lack jurisdiction over sales by the State of Alaska, its duty to inquire into and weigh the impact of such activities on jurisdictional proposals is clear. 2/ And in certificating jurisdictional proposals, the Commission may attach appropriate conditions required to protect consumers. 3/ Thus, the Commission could, for example, attach reasonable conditions to any certificate issued to El Paso to require that its contract for LNG ocean transportation be consistent with public interest findings.

1/ Marathon Oil Co., Opinion No. 735 issued June 23, 1975.

2/ Public Service Commission of New York v. F.P.C., 287 F.2d 143, 146 (D.C. Cir. 1960); F.P.C. v. Transcontinental Gas Pipe Line Corp. 365 U.S. 1(1961).

3/ Henry v. F.P.C., 513 F.2d 395, 403 (D.C. Cir. 1975); Distrigas Corp. v. F.P.C., 495 F.2d 1056, 1064 (D.C. Cir. 1974).

The State of Alaska's position, in the Presiding Judge's view, is contrary to the law and to effective or equitable regulatory control. The sole basis for its denial of jurisdiction is the claim that a State is not a "person" within the meaning of Section 2 of the Act. 1/ Thus, activities which, by their nature, Congress intended to place under regulation are said to be exempt when performed by a tate. There is no such gap in the law, and one should not be created. The producing and energy-rich tates of the nation, by virtue of their royalty interest where production is from state land and their increasing propensity to reserve the right to take that interest in kind, will have the ever-growing ability to dispose by sale of larger and larger volumes of gas and will expand such a gap to permit larger and larger volumes to escape regulatory control. In this proceeding alone, Alaska has recently entered into contracts to sell in interstate commerce up to 2.6 Tcf of its royalty gas.

Alaska's jurisdictional argument, moreover, is hardly compatible with the Act's purpose to afford consumers an effective bond of protection against excessive rates 1/ or the intention of Congress "to give the Commission jurisdiction over the rates of all wholesales of natural gas in interstate commerce ..." (emphasis added). 2/ Furthermore, Alaska's essential premise is undercut by the holding in F.P.C. v. Corporation Comm'n of Oklahoma, 362 F. Supp. 522; aff'd 415 U.S. 961 (1974), that a state agency is a "person" within the meaning of Section 2 of the Act and thus the U.S. District Courts have jurisdiction under Section 20(a) to enjoin its actions violative of the Act or regulations thereunder. The question of jurisdiction over Alaska's proposed sales is not squarely at issue in this proceeding, and the parties have not provided legal argument on the question only because sales contracts were not filed earlier. The need for the Commission to give prompt attention to and definitively resolve the matter is apparent, since any attempt to finance these projects must be predicated on knowledge of the transactions that are jurisdictional. 3/

1/ Atlantic Refining Co. v. P.S.C. of New York, 260 U.S. 378(1959).

2/ Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672, 682 (1954).

3/ The same claim by the State of Texas is now pending before the Commission in Public Service Company of North Carolina, Inc., Docket No. RP76-103. The State of Alaska has intervened in that proceeding. A finding of jurisdiction there could be dispositive of the issue here.

As already stated, Alaska, through its Commissioner of Natural Resources, has agreed to sell up to 2.6 Tcf of gas to Tenneco Alaskan, Inc. (50%), Southern Natural Gas Co. (25%), and El Paso Natural Gas Co. (25%) and has submitted copies of the contracts for the record (ALA-35). 1/ Among other things, the contracts require the purchasers to actively support and seek ultimate selection of "a trans-Alaska gas pipeline system" (read "El Paso Alaska") and reserve to the State of Alaska the right to reduce daily deliveries by an amount up to 25% at any time during the first 5 years commencing with the date of first delivery, 50% during the next 5 years, 75% during the third 5-year period, and 100% after 15 years. 2/ The purpose of such reservation is to insure that the amount of royalty gas exported from the State is "surplus"--whatever that means--to the "State's intrastate domestic and industrial needs"--whatever that means. In the event Alaska exercises its right to take reserved gas, it will reimburse the purchaser on a pro rata basis for the purchaser's undepreciated investment in facilities upstream of the trans-Alaska pipeline. 3/ The agreements may be terminated by the State in the event the El Paso Alaska project is disapproved.

There can be little doubt that the Commission would decline to certificate long-term sales in interstate commerce on terms that would permit the seller, in its sole discretion, to reduce the level of service in the manner contemplated by Alaska. Section 7 of the Natural Gas Act would require the Commission either at the outset to find such future abandonment in the

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1/ The contracts are not dated because their final execution is to occur at a future date, although all parties are said to have agreed upon their terms. Upon reflection, Alaska decided not to seek a reopening of the record for the appearance of a state witness with respect to the contracts.

2/ Given the contract terms, such support is entitled to little weight.

3/ Presumably the facilities referred to are gas gathering and conditioning facilities in the Prudhoe Bay Field.

public interest or to abide the event and pass upon the question after hearings at the appropriate future time. This is especially the case where, as here, the feasibility of substantial transportation facilities rests in part on the sales in question. Unfortunately, regardless of the jurisdictional issue involved, the 1976 Alaska Natural Gas Transportation Act would operate to permit Alaska to withdraw its royalty gas from the interstate market in the manner which its contracts contemplate (§ 13(b)).1/ The result of such withdrawal under these contracts could be the future idling of up to 12.5% of the capacity in the El Paso LNG plant, LNG shipping, the regasification plant on the California coast, and the incremental lower-48 transportation facilities, all at the expense of lower-48 consumers. However, imposition of conditions requiring Alaska to reimburse the just and reasonable costs to the other users, if withdrawal is exercised, is apparently implied within section 13(b), and it would be expected that the Commission would insist on such reimbursement.

1/ Section 13(b) provides:

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

III

GAS SUPPLY

Gas supply is always an important consideration in any certification case for a new pipeline. In the usual proceedings, of course, the supply is under contract and the underlying reserves and deliverability can be ascertained. As discussed, supra, there are no contracts for sale on file here, but this is not fatal to this aspect of the case because there is little dispute as to the recoverable reserves at Prudhoe Bay (discussed) infra). Moreover, now that the proposed Prudhoe Bay production agreement for hydrocarbon recovery has been submitted to the State of Alaska for approval, conclusion can be reached as to a possible throughput of 2.0 Bcf/d - 2.5 Bcf/d commencing between 1981 and 1983. 1/ The importance of the probability of other Alaskan reserves, as well as probability of location of future Alaskan reserves, is also of great concern. If one assumes that there is a great likelihood of discoveries in Alaska east of Prudhoe Bay on the North Slope or in the adjacent Beaufort Sea, a pipeline alignment in that direction would take on added significance. An additional factor, of course, is whether one further postulates that any discovery east of Prudhoe quickly will be exploited whether or not a gas transmission pipeline would have previously been built. Large discoveries in Naval Petroleum Reserve No. 4 (NPR #4) or the Alaska interior may argue for a different result. Again, discovery near Fairbanks which would meet Fairbank's needs might modify the position of either the conservation groups or the State of Alaska.

Unlike Prudhoe Bay reserves, there is no agreement on the size of the Mackenzie Delta reserves. These reserve figures are critical to any determination of a choice between these competing pipelines, for the economic viability of the Arctic Gas proposal is directly dependent on the ability of the Mackenzie Delta reserves to deliver significant volumes of gas by 1983. Each party draws a different conclusion from a projection of Mackenzie Delta reserves.

An appreciation of projected Canadian gas supply from traditional Canadian supply areas also is important. These projections on both Westcoast, AGTL and PGT are necessary for determining the need for additional pipeline capacity, since the level of Canadian supplies from Canadian traditional sources will give some indication of the level that can be expected for continued Canadian exports (discussed, infra). Also, it is necessary for an informed decision as to whether Canada needs frontier gas and when and whether the NEB would favor Arctic Gas' proposal for bringing Mackenzie Valley Gas to market (also discussed infra).

1/ Technical Report on Proposed Plan of Operations of the Prudhoe Bay Unit (ALA-33).

Also important is the prediction of U.S. production--particularly in the Permian and Hugoton-Anadarko Basins. A reduction in long-term cost would be realized on the El Paso proposal if substantial volumes of gas were available for displacement from these fields in the future so that equivalent quantities of Alaskan gas would not have to be moved off of the west coast. Large discoveries might affect marketability of Alaskan gas (also discussed elsewhere, infra).

A. Alaska

1. The North Slope (in General)

The North Slope of Alaska encompasses an 80,000 square mile area, extending approximately 600 miles from the Canadian Border to the Chukchi Sea and up to 200 miles from the Brooks Range to the Arctic Ocean. The North Slope can be divided into three regions: in the west, the Naval Petroleum Reserve No. 4 (NPR #4); a central region containing the Prudhoe Bay Field in the north; and in the east, the Arctic National Wildlife Range.

The North Slope has been studied by geologists since the early 1900's. The first wells were drilled by the U.S. Navy, which drilled 36 exploratory wells on NPR #4 between 1944-1953. By the end of 1972, an additional 67 exploratory wells were drilled on the North Slope. These later wells penetrated 9,854 feet of sediments per well, which was twice the average depth of the exploratory wells in NPR #4. It is apparent that exploration on the Slope has only begun: only 110 exploratory wells had been drilled on the 80,000 square mile area, as of December 1974 (AA-H); from May 1975 - November 1975, 13 exploratory and step-out wells were drilled on the North Slope (69/10,542); as of January 15, 1976, about 60 "wildcat" or exploratory wells had been drilled on the North Slope, exclusive of NPR #4 and the Prudhoe Bay Field.

2. Positions of the Parties

Initial and Reply Briefs were filed specifically on this subject by Arctic Gas, Alcan and El Paso, while Staff filed only an Initial Brief and the State of Alaska a Reply Brief. The producers have periodically responded to inquiries on this issue to permit a more complete record.

There is no significant disagreement concerning the amount of reserves in the Prudhoe Oil Pool on the North Slope. All parties agree that in-place reserves are in excess of 35 Tcf, comprising a vast finding obviously capable of supporting a natural gas pipeline or LNG transportation system to the lower 48 states.

The main disagreements are two: (1) the gas deliverability levels one can expect from an oil/gas field (Prudhoe Oil Pool) which is rate-sensitive (i.e., gas deliverability levels affect ultimate oil recovery), and (2) the extent and location of undiscovered recoverable reserves that exist in other hydrocarbon areas of northern Alaska.

First, Alcan estimates a maximum daily average gas volume in the range of 2.0 Bcf/d, while Arctic Gas, El Paso and the producers estimate initial deliverabilities of 2.0 Bcf/d - 2.5 Bcf/d. Alcan argues that it is presently unwise to estimate gas deliverabilities at levels substantially above 2.0 Bcf/d. It bases this conclusion on two related factors: (a) the Prudhoe Bay Field is rate-sensitive, and daily gas sales above 2.0 Bcf/d may reduce ultimate oil recovery; (b) it is clear that water injection is helpful, if not in fact necessary, to attain gas deliverabilities above 2.0 Bcf/d without significantly reducing oil recovery, and the producers have not yet proposed to construct a water injection system.

Arctic Gas, El Paso and Staff argue that the field will be operated so as to allow initial deliverability levels of 2.0 Bcf/d - 2.5 Bcf/d. Water injection may not be needed to sustain these deliveries with no effect on oil recovery. If water injection is required and economically feasible, such an injection system will be put in place. At that time, the higher capacity and more readily expandable El Paso and Arctic Gas pipelines will be better able to handle the increased flow.

Further, Alcan argues that the only other significant areas of hydrocarbon potential in the north are onshore in the Wildlife Range and offshore, especially northwest of Prudhoe Bay, and that these areas are inaccessible, both from technological, economic and environmental viewpoints. Arctic Gas argues that there are significant reserves located west and offshore north and northwest of the Prudhoe Bay Field, to which it is as well situated as the other proposals. Moreover, the potential of areas east and offshore east of the Canning River is most significant, and only the Arctic Gas route passes through these areas. Arctic Gas adds that only its system has the configuration and potential capacity to transport these added reserves. El Paso, in its Initial Brief, states that additions to existing reservoirs in the leasable North Slope area seem likely to increase gas sales. However, on Reply Brief, El Paso states that it agrees with Alcan that potential reserves on the North Slope should be ignored. Staff agrees that the most promising areas of potentially large gas reserves are the Wildlife Range and Beaufort Sea area. Staff argues that Arctic Gas is best able, in both logistics and capacity, to transport these potential reserves.

3. Prudhoe Bay Field

a. Description and Drilling History

Most of the proved reserves located to date on the North Slope have been found in the Prudhoe Bay Field. The Prudhoe Bay Field is located on the flat-lying coastal plain on the north-central portion of the North Slope, near the Beaufort Sea. The field lies approximately 200 miles east of Point Barrow and 50 miles east of NPR #4, 640 miles north of Anchorage, 120 miles north of the Brooks Range, and 180 miles west of the Canadian border.

The most significant rock formations in the Prudhoe Bay Field in terms of hydrocarbon production are, in ascending **horizon** order: Lisburne Group carbonates (containing Lisburne Oil Pool); Sadlerochit Formation, Shublik Formation, Sag River Formation (together officially designated Prudhoe Oil Pool); and Kuparuk River sands (containing Kuparuk Oil Pool). The age of the rock here includes Jurassic, Triassic, Permian and Pennsylvanian. The Alaska Oil and Gas Conservation Committee has officially defined the Prudhoe Oil Pool to include the Shublik Formation, the Sag River Formation and the Sandstone unit of the Ivishak Member of the Sadlerochit Formation. Most of the information presently available concentrates on the Prudhoe Oil Pool, and particularly the Sadlerochit Formation, since most of the hydrocarbons in the Prudhoe Oil Pool occur in this sandstone.

The Sadlerochit reservoir, early Triassic in age, is considered to be a deltaic deposit that varies in thickness from more than 600 feet in the central and southern parts of the field to 300 feet on the northeastern part. Lithologically, it consists of fine-to-coarse-grained sandstones, conglomerates, siltstones and occasional thin layers of shale. The accumulation of hydrocarbons in the Sadlerochit is controlled partly by a westward plunging faulted anticline truncated on the northeast flank, and partly by the unconformable Early Cretacious Unnamed shale which truncates the formation in the east. Faults are assumed to be vertical through the reservoir, and all faults except those that form the boundaries to the reservoir are considered to be nonsealing. Fluid movement across faults is considered likely.

The fluid columns in the reservoir are the classical water aquifer overlain by trapped liquid hydrocarbons capped with an associated gas column. Within the sandstones, the oil column reaches a maximum of 460 feet, with up to 350 feet of overlying gas cap. Hydrocarbon accumulations are encountered at subsea depths of 8000 feet-9000 feet. Gas-oil and oil-water contacts generally lie at approximately 8578 feet and 9008 feet, respectively.

In the Prudhoe Bay Field, the area of the Kuparuk Oil Pool is 198 square miles, Sadlerochit 480 square miles, and Lisburne 282 square miles. These areas overlap considerably so that the areal extent of the entire field is approximately 660 square miles. Within a defined pool area, there may be a considerable amount of acreage that is unproductive because of irregularities of geology and fluid saturation. This has led to some confusion as to the stated area of the oil pools. It is generally accepted that the productive area of the Sadlerochit Formation is approximately 200 square miles.

In 1968, Arco completed two wells located 7 miles apart in the since-named Prudhoe Oil Pool in Prudhoe Bay Field. This marked the beginning of exploration in the area. As of January 15, 1976, 144 wells have penetrated the Sadlerochit Formation of the field, and four of these are now capable of producing. Most of the other wells would be capable of producing with some mechanical preparation. Thirty-one wells have penetrated all or part of the Lisburne Formation, and permits have been issued for five wells that are now drilling or will be drilling in the near future. Eighteen wells have penetrated the Kuparuk River Formation. 1/

The gas zone of the Sadlerochit extends slightly into Prudhoe Bay. To date, only one well has been completed beneath the Arctic Ocean. This well, directionally drilled from an onshore location, is at present classified as a suspended oil well.

Today, there are 13 interest holders in the Prudhoe Bay Field. The three major producers are Exxon - 8.7 Tcf of proven reserves, Sohio - 7.1 Tcf of proven reserves, and Arco - 7.08 Tcf of proven reserves. The exact ownership of each of the producers will not be determined until a unitization agreement is drafted and approved by the State - sometime before oil production begins.

b. Prudhoe Oil Pool - Reserve and Deliverability Estimates

Several studies have been made to determine the quantity of gas reserves in the Prudhoe Oil Pool. A comparison of the Sadlerochit in-place reserve estimates, including both solution and gas-cap gas, shows the various conclusions to be quite similar:

1/ The Alaskan Division of Oil and Gas, at the end of October 1975, announced that there are 138 oil and gas wells completed in Prudhoe Bay. The average well there had a deliverability of 5,000 barrels/d (69/10,542).

DeGolyer & MacNaughton ("D&M" - Arctic Gas consultants) - 35.8 Tcf.
El Paso - 35.1
Van Poollen (State of Alaska consultants) - 40.4 1/
Core Labs (Alcan consultants) - 41.9

Differences in the salable reserve estimates result mainly from different recovery and shrinkage factors employed. The estimates for the Sadlerochit are:

D&M - 20.5 Tcf
El Paso - 24.3 Tcf

In some parts of the fields, the distinction between the Shublik and the Sadlerochit is not definite. When the Shublik has pay in it, D&M has included it in the pay counts of the Sadlerochit. Otherwise, D&M has given very little pay count to the Shublik formation. D&M also estimated an additional 1.98 Tcf of salable reserves in the Sag River Sandstone.

D&M employed a recovery factor of 76% for associated gas and 60% for solution gas. The shrinkage factor was estimated at 17%, but this included removal of carbon dioxide, liquids, 2/ and gas utilized for fuel on the lease (9/1238).

1/ In a report styled "Prediction of Reservoir Fluid Recovery, Sadlerochit Formation, Prudhoe Bay Field, January 1976 (Ala-4).

2/ Exxon estimated that the pretreated gas will contain: methane - 72.92%, ethane - 6.9%, propane - 3.72%, iso butane - 0.58%, normal butane - 1.23%, pentanes plus - 1.42%, CO_2 - 12.71%, nitrogen - 0.51%, with a water content of 820 lbs/MMcf. The treated gas will contain: methane - 85.11%, ethane - 7.70%, propane - 3.99%, iso butane - 0.50%, normal butane - 0.73%, pentanes plus - 0.22%, CO_2 - 1.00%, nitrogen - 0.75%, with a tentative water content of 0.2 lbs/MMcf.

It is generally accepted that the gas contains 10% - 12% CO_2. As much as 10 million bbl of natural gas liquids might be produced during the treating stage, without processing. In addition, a gas-cap gas condensate yield of about 35 bbl per MMcf of separator outlet gas is expected initially from the separator facilities.

El Paso employed a recovery factor of 86.6% for both associated and solution gas and a shrinkage factor of 20%, including removal of carbon dioxide, evidently liquids, and "the fuel in shrinkage of the processing" /sic/ (8/1392).

The two reservoir simulation studies found somewhat lower recovery factors. Van Poollen determined that gas recoveries ranged up to 72.33% of original gas in place for the highest gas sales rate case of 4.0 Bcf/d. Core Labs found gas recoveries ranged from 39.4% - 69.3%. The producers expect ultimate gas recovery in the 75% - 80% range, over a 35-year period.

Finally, it is significant to note that the DOI Report to Congress (EP-231), using a weighting methodology whereby probable reserves are discounted 30% and possible reserves 70%, has estimated that expected additions to proved salable reserves by 1985 in the Sadlerochit will be 6.8 Tcf.

Respecting deliverability, all parties, save Alcan, have advocated a Sadlerochit deliverability rate above 2.0 Bcf/d. The North Slope producers have stated, both in a letter to the Presiding Judge and in their proposed plan of operation, that gas pipeline sales of at least 2.0 Bcf will be made whenever a gas pipeline system and gas treating plant are in place. The producers envision sales up to 2.5 Bcf/d depending upon reservoir performance. Alcan recommends a maximum daily average in the range of 2.0 Bcf/d. For the sake of completeness, detailed deliverability schedules are inserted below.

D&M postulated a 2.25-Bcf/d deliverability (AA-H), based upon information provided by the producers concerning gas sales levels they anticipated. The D&M 2.25 estimate includes 1.25 Bcf/d of gas-cap gas and 1.00 Bcf/d of solution gas, assuming an oil production of 1.5 million bbl/d:

	Gas Deliveries – MMcf	
Year	Average Daily	Annual
1980 (6 Mos.)	2,000	365,000
1981	2,000	730,000
1982	2,040	744,600
1983	2,250	821,250
1984	2,250	821,250
1985	2,250	821,250
1986	2,250	821,250
1987	2,250	821,250
1988	2,250	821,250
1989	2,250	821,250
1990	2,250	821,250
1991	2,250	821,250
1992	2,250	821,250
1993	2,250	821,250
1994	2,250	821,250
1995	2,250	821,250
Total Delivery – MMcf		12,515,850
Total Delivery as Percent of Salable Gas Reserve		56

El Paso, using a three-dimensional computer model, estimated deliverabilities of up to 3.3 Bcf/d (EP-53):

Year	Oil Production, MBbls/D			Wellhead Gas Production, MMcf/D			Gas Available to Pipeline MMcf/D
	Main Area	West Area	Total	Main Area	West Area	Total	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	1,191	--	1,191	828	--	828	1/
2	1,190	--	1,190	800	--	800	1/
3	1,190	--	1,190	801	--	801	1/
4	1,501	--	1,501	1,566	--	1,566	1,253
5	1,498	--	1,498	3,815	--	3,815	3,052
6	1,496	--	1,496	4,106	--	4,106	3,284
7	1,500	--	1,500	4,078	--	4,078	3,262
8	1,527	15	1,542	4,105	10	4,115	3,292
9	1,500	15	1,515	4,077	10	4,087	3,270
10	1,272	15	1,287	4,101	10	4,111	3,289
11	847	15	862	4,104	11	4,115	3,292
12	589	15	604	4,105	11	4,116	3,293
13	467	15	482	4,116	11	4,127	3,302
14	387	15	402	4,110	11	4,121	3,297
15	346	15	361	4,136	12	4,148	3,318
16	262	15	277	4,078	12	4,099	3,272
17	219	15	234	4,095	12	4,107	3,286
18	196	15	211	4,104	13	4,117	3,294
19	186	15	201	4,078	13	4,091	3,273
20	175	15	190	4,112	14	4,126	3,301
21	172	15	187	4,078	14	4,092	3,274
22	150	15	165	3,726	15	3,741	2,993
23	119	14	133	2,746	15	2,761	2,209
24	96	12	108	2,117	19	2,136	1,709
25	72	11	83	1,500	20	1,520	1,216
26	53	10	63	889	28	917	734
27	40	9	49	517	34	551	441
28	34	8	42	322	46	368	294
Production for 28 Year Period:							
Oil, Billion Bbls.	6.7	0.1	6.8				
Gas, Trillion Cu. Ft.				31.1	0.1	31.2	24.3

1/ Gas injected.

Staff, using a material balance equation rather than a computer model and making various assumptions, estimated annual deliveries ranging from an average of 2.25 Bcf/d - 4.0 Bcf/d (ST-31):

Year	Production MBbls.	Cumulative Oil Production, MBbls	Annual Gas Sales, M^3CF	Cumulative Gas Sales, M^3CF
1977	165,600	165,600		
1978	438,000	603,600		
1979	547,500	1,151,100		
1980	547,500	1,698,600		
1981	547,500	2,246,100		
1982	547,500	2,793,600	48.6	48.60
1983	547,500	3,341,100	821.25	869.85
1984	547,500	3,888,600	821.25	1,691.10
1985	542,025	4,430,625	821.25	2,512.35
1986	467,200	4,897,825	821.25	3,333.60
1987	372,300	5,270,125	821.25	4,154.85
1988	328,500	5,598,625	821.25	4,976.10
1989	280,320	5,878,945	821.25	5,797.35
1990	239,075	6,118,020	821.25	6,618.60
1991	204,035	6,322,055	821.25	7,439.85
1992	173,740	6,495,795	821.25	8,261.10
1993	148,190	6,643,949	1006.4	9,267.50
1994	126,655	6,770,604	1460	10,727.50
1995	108,040	6,878,644	1460	12,187.50
1996	91,980	6,970,624	1460	13,647.50
1997	78,475	7,049,099	1460	15,107.50
1998	67,160	7,116,259	1460	16,567.50
1999	57,305	7,173,564	1460	18,027.50
2000	48,910	7,222,474	1460	19,487.50

Core Labs, utilizing a two-dimensional computer model with various operating plans, suggested a build-up of gas deliveries from 1.2 Bcf/d - 2.4 Bcf/d. However, Alcan witness Robert Keener testified that he recommended to Alcan management daily average gas volumes in the range of 2.0 Bcf/d. This recommendation was based on the Van Poollen and Core Lab conclusions that gas sales above 2.0 Bcf/d would affect ultimate oil recovery, especially if there is no water injection.

c. Lisburne and Kuparuk - Reserve Estimates

The extent of reserve potential in the Lisburne and Kuparuk have remained a curious mystery during these proceedings. Neither the producers nor the State were willing to admit having addressed the question, basically saying there were more important things to do and they would get to it later. While hydrocarbon potential has been established in the shallower

Kuparuk and deeper Lisburne, it appears that future development or complete disclosure of past drilling will be necessary to establish the producing capabilities of these formations. State of Alaska witness O.K. Gilbreth testified that there is a significant amount of hydrocarbon reserve estimated in the Kuparuk, although the Lisburne remains a large question mark. (96/14,787-788). The DOI Report to Congress (EP-231) estimated 3.9 Tcf of "probable" reserves in these formations and 7.1 Tcf of "possible" reserves. Using their weighting methodology, the Report concluded that there are 4.9 Tcf of salable reserves expected to be proved in these formations by 1985. For all this record knows, there could be a deliverability of as high as 0.5 Bcf/d by 1982 from these formations.

d. Prudhoe Bay Field - Deliverability Considerations and Conclusions

All parties agree that it is impossible to determine precisely, at the present time, the daily deliveries to be expected from the Prudhoe Bay Field. The main reasons for this uncertainty are that there is no production history for the reservoir, it is rate-sensitive, (i.e., the rate of gas deliveries will affect ultimate oil recovery), and, of course, neither the producers nor the State have favored the public with a definitive plan of operations.

A key factor in the recovery of hydrocarbons is pressure maintenance in the reservoir. Pressure maintenance can be achieved by aquifer response, gas reinjection, produced water reinjection or source water injection. An aquifer is present in the Prudhoe reservoir, and produced water reinjection will be employed. 1/

It has also been assumed that gas reinjection will occur until the time that the gas pipeline is completed. This reinjection gas, serving to maintain reservoir pressure, will enhance oil recovery. At the time that gas pipeline construction is completed, it has been assumed that only produced gas above the projected sales levels will be reinjected. There has been some discussion on the record concerning the possibility that all produced gas could be reinjected for an indefinite period after the gas pipeline is completed. It now seems clear that

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1/ The Van Poollen study (Ala-4) found that a aquifer containing about 1.8 trillion barrels of water occurs downdip to the hydrocarbon-bearing deposit. El Paso witness A.M. Derrick testified that about 7 billion barrels of water will be produced during a 28-year period (9/1439).

such reinjection methods would not be detrimental, but would actually increase oil recovery. There is disagreement over the fuel requirement of reinjecting all produced gas.

It now seems clear, at least from the producers' proposed plan of operations, infra, that gas will be made available for sale at the time of gas pipeline completion. However, there is still some uncertainty concerning the amount of gas that can and will be sold without adversely affecting oil recovery. The highly-regarded Van Poollen Report (Ala-4), confirmed that the rate of gas production will affect the ultimate oil recovery. While Van Poollen determined that highest oil recoveries were obtained under conditions of water injection and no gas sales, he also found that these higher ranges of oil recovery can be approached under conditions of 2.0-Bcf/d gas sales and water injection, if certain operating limits are changed. Moreover, while increasing gas sales above 2.0 Bcf/d for a given maximum sustained oil rate resulted in successively reduced oil recoveries, the higher recovery rates can be reached by further water injection (96/14,761-764).

Given the aforementioned characteristics of the field, it appears that the producers will not opt for gas sales above 2.0 Bcf/d until further analyses and reservoir performance studies demonstrate that higher sales levels will not jeopardize oil recovery. However, the producers have submitted a technical report on their recommended plan of operations (Ala-33), which indicates the production strategies they intend to follow (see Appendix C). The plan will be submitted to the Alaska Oil and Gas Conservation Committee for approval, pursuant to that agency's duty to regulate the operation and production of wells for conservation purposes. The producers state that once the necessary pipeline and conditioning plant are in place, gas deliveries of at least 2.0 Bcf/d will commence. No one at this time questions the producers' statement that there is a 4-6 year lead for constructing the gas conditioning plant. The volume itself is termed as conservative, and they state that initial gas deliveries of up to 2.5 Bcf/d may be justified without affecting ultimate oil recovery. Produced water will be reinjected into the field, and the producers cite studies indicating further potential for increasing oil recovery by implementing a source-water injection program. However, at least two years of testing are said to be necessary after the field goes into oil production before the final decision is made to construct source-water injection facilities. In approving the plan, an issue may exist between the producers and the State as to the need for, and timing of, source-water injection.

The vast weight of the evidence is that between 2.0 Bcf/d - 2.5 Bcf/d of gas will be available initially from the Prudhoe Bay Field. Although the uncertainty concerning reservoir performance and the possible necessity of source-water injection preclude exact estimates, the projections of Arctic Gas, El Paso and Staff, in addition to the plan of operations proposed by the producers, support a finding of initial deliverability of 2.0 Bcf/d - 2.5 Bcf/d. The presently proved reserves in the Prudhoe Oil Pool are clearly able to support the aforementioned deliverability volumes. Clearly the decision to increase deliveries over the minimum 2.0 Bcf/d or to construct a source-water injection system (about $1 billion) will involve economic trade-offs which will be analyzed initially by the producers and the State.

In addition, if one includes the estimated Sadlerochit, Lisburne and Kuparuk additional volumes of 11.7 Tcf by 1985 (EP-231), it is obvious that the 2.0 Bcf/d - 2.5 Bcf/d estimate is indeed conservative.

4. Other North Slope Reserves

While the conclusion has been reached that initial sales of 2.0 Bcf/d - 2.5 Bcf/d are likely from the Prudhoe Bay Field, the evidence of record suggests that sales appreciably above this level will be available from the North Slope region.

Estimates of potential reserves on the North Slope, other than Prudhoe Bay, have varied considerably. The Division of Geological and Geophysical Surveys (DGGS) of the State of Alaska, in June 1974, stated that "speculative recoverable gas" for the onshore area of the North Slope totaled 41.8 Tcf, while offshore gas potential in the Beaufort and Chukchi Sea provinces equalled 46.5 Tcf. 1/ The Potential Gas Committee estimated, in 1973, that the "speculative potential gas supply" on the North Slope totaled 75 Tcf. The United States Geological Survey found, in 1975, the "undiscovered recoverable resources" to be between 19 Tcf - 99 Tcf. 2/ Finally, EP-231, again using a weighting methodology, estimates North Slope additions by 1985 at 8.4 Tcf, excluding the Wildlife Range, NPR #4, and the Prudhoe Bay Field.

There are several specific regions of the North Slope which could logistically support additional deliveries into the systems of one or more of the three pipeline applicants. 3/

1/ DGGS defines "speculative recoverable resources" as those which are completely undiscovered and which after discovery can reasonably be expected to be produced using present technology and economic conditions.

2/ "Speculative potential gas supply" and "undiscovered recoverable resources" approximate "speculative recoverable resources." Exxon's answers to interrogatories state that the USGS estimates undiscovered reserves on the North Slope to be from 14 Tcf - 49 Tcf.

3/ All parties agreed that the interior basins of Alaska do not contain promising amounts of gas (about 2 Tcf).

Of course, Arctic Gas, because of its larger potential capacity and cheaper expansibility, would be best able to transport the additional volumes from any North Slope source.

Alcan, not surprisingly, presented the most conservative appraisal of potential North Slope fields. Alcan witnesses James Lowell and Gary Newman testified vigorously and persuasively that a Prudhoe-type structure is unlikely to occur anywhere else onshore west of the Wildlife Range and in particular NPR #4. Lowell estimated 14.5 Tcf in the range and 10.5 Tcf scattered in smaller onshore structures west of the range, including only 5-6 Tcf in scattered fields in NPR #4 (201/34,386).[1] Witness Lowell testified that the probability of another Prudhoe-type accumulation is greatest offshore, especially northwest of Prudhoe Bay. If one accepts Alcan's estimate as the minimum amount of potential reserves existing on the North Slope, the result still leaves areas of significant reserves, onshore east of the Canning River and offshore in the Beaufort Sea. Logistically, without regard to capacity, Arctic Gas would be in the best position to transport these hydrocarbons.

Other witnesses were more optimistic concerning North Slope fields, particularly NPR #4. NPR #4 is a 22-million acre area in the western section of the North Slope-- roughly the size of Indiana. Only 36 exploratory wells were drilled by the Navy from 1944-1953 in this area, when efforts were suspended. Both oil and gas were found in these early efforts, but reserves were not deemed large enough to warrant a pipeline to transport them. Between 1953-1974, the only drilling was in the South Barrow Field, a few miles east of Barrow, where currently seven producing gas wells provide energy to all federal agencies and urban populations in the Barrow area. The Arab oil embargo in 1973 prompted Congress to establish an exploration program in NPR #4. This $7.5-million program is designed to determine locations and magnitudes of oil and gas accumulations during a 7-year time frame beginning in 1974. Plans call for drilling 26 test wells. To date, two of these wells have been drilled.

Congress recently passed, and the President signed, P.L. 94-258 ("National Petroleum Reserve in Alaska," 42 USC § 6501 et seq.). This statute designates NPR #4 as a "national petroleum reserve" and transfers administration of the area to the Secretary of the Interior as of June 1, 1977. § 6504 of the Act provides that the Navy shall continue the ongoing petroleum exploration program until June 1, 1977, at which time the Secretary of the Interior shall commence further petroleum

1/ Alcan witness Lowell testified that the chance of finding another Prudhoe-type structure in NPR #4 is dim, since in his opinion the geological ingredients of a Permian-Triassic reservoir in most of the area and its contact with the lower cretaceous sourcing shales are missing (201/34,384-390).

exploration. § 6504(d)(3) states that the Secretary shall report annually to the Congress on the progress of the exploration. § 6505 provides that the President shall direct the appropriate agencies to determine the best procedures to be used in the "development, production, transportation and distribution" of petroleum resources in the reserve. This statute should substantially encourage exploration efforts in the reserve.

Today, hydrocarbon potential in NPR #4 remains uncertain. Lieutenant Commander Todd Reuling of the United States Navy testified that proved reserves in NPR #4 are 167 Bcf, which represents about 0.16% of total estimated gas supply there. Lt. Comm. Reuling stated that the Arctic Institute of North America concluded that potential gas in NPR #4 totaled 78.65 Tcf, assuming a low potential recoverable oil estimate of 14.3 billion bbls. However, DOT witness Max Taves testified that, in a yet unpublished study, potential reserves in the area are estimated at only 14.3 Tcf (175A/29,089-090).

In sum, while the hydrocarbon potential in NPR #4 is presently unclear, the possibility of large finds in that area remains. Logistically, all 3 applicants could profit from reserves here, although Arctic Gas could most readily handle the additional volumes, while Alcan would be at a severe pipeline capcity disadvantage.

B. Mackenzie Delta Area

1. Description and Drilling History

The Mackenzie Delta hydrocarbon-bearing area is located roughly at Latitude N. 68°-70° and Longitude W. 133°-137° in Canada's Northwest Territories. It is centered at the juncture of the Mackenzie River and the Beaufort Sea, and extends into the sea. The entire Delta area is 15,000 square miles.

Geologically, the Delta area can be described as a northward-plunging, graben-like depression in which accumulations of Mesozoic and Tertiary clastics attain thicknesses over 30,000' at the northern extremity of the basin. Approximately one-half of these sediments are Crataceous and Tertiary in age.

Prior to 1970, exploration for hydrocarbons in the Delta area was limited. Early exploration did result in minor shows of oil and gas from discontinuous sandstone in the area. It was the announcement in 1970 that the Imperial Oil Atkinson Point H-25 well flowed oil that resulted in a rejuvenation of interest in the area and intensified drilling activity. As of June 1, 1976, 73 wells had been completed in the Delta area; 21 of these were completed as gas producers, 4 as oil, 5 as gas and oil, and

43 dry wells. This is an overall success ratio of 41% (AA-118). There were then 5 or 6 additional wells being drilled in the area.

Many of the well completions occurred prior to December 1974. Between December 1974 and July 31, 1975, 9 developmental wells were drilled, of which 4 were successful. Moreover, 11 "wildcat" wells were drilled, of which 1 was successful (79/12,115-116; 80/12,270). Up until July 31, 1975, all the drilling was located in 8 fields: Taglu, Parsons Lake, Adgo, Mallik, Niglintgak, Reindeer, Titalik, and Ya Ya. Of these, Taglu and Parsons Lake are the most significant, with Taglu being located in the northeast section of the Delta area and Parsons Lake in the southeast section. Taglu is the only field to date for which field limits are fairly well defined.

Between July 31, 1975, and June 1, 1976, drilling activity continued at approximately the same level as in prior years. During this most recent period, 8 wells were drilled in existing fields, of which 6 tested oil or gas and 2 were dry. Also, 2 new offshore field discoveries were made-- Garry and North Netserk fields (Arctic Gas witness E. A. Olson, 178/29,585). 1/

Numerous areas remain untested in the delta area, particularly in the Beaufort Sea, which is known to have large structural features with hydrocarbon potential. To date, the Delta area has had a drilling density of only slightly over one well/200 square miles. Today, the three major producers in the delta area are Gulf, Imperial and Shell.

2. Position of the Parties

The briefs encompassing Alaskan gas supply, described supra, also discussed the Mackenzie Delta. Foothills also filed Initial and Reply Briefs on this issue.

Arctic Gas argues that all proved, probable and possible reserves from the 8 delta fields must be considered in certificating a pipeline. It is proper, it says, to consider all these reserves because the intensity of drilling to date in the delta has been relatively slight; Arctic Gas considers it realistic

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1/ Olson's description of the July 31, 1975-June 1, 1976, drilling differs somewhat from that offered by El Paso witness Dayne Adams. Adams agreed that 10 wells were completed during this period, but stated the results were 5 oil and gas, 4 dry and 1 tight gas well without reservoir porosity (160/26,348-351). Unfortunately, neither the Adams nor the Olson testimonies exactly coincide with AA-118, the Arctic Gas exhibit identifying all Mackenzie Delta drilling activity.

to assume that by the time the pipeline is flowing, all these reserves will be proved and additional discoveries will be made. Finally, Arctic Gas argues that early access to the Mackenzie Delta reserves is in the best interests of Canada and the United States.

El Paso maintains that only proved reserves from the 3 largest fields should be considered in this proceeding. Citing an alleged "discouraging trend" in recent delta discoveries, El Paso argues that even the DeGolyer & MacNaughton (D&M) proved reserve figures may be speculative, total reserves are likely to remain constant in the future, and it is only economically feasible to connect the 3 largest fields at this time. In the alternative, El Paso argues: (1) that if a discounting methodology is used, the lower proved reserves estimate of the Canadian Petroleum Association should be employed; (2) if the Commission considers proved and probable reserves, a discounting methodology should be used.

Foothills agrees with Arctic Gas that proved, probable and possible reserves must be considered, although it uses the terminology of "most likely reserves." However, Foothills argues that the development of the Mackenzie Delta is of no immediate urgency to Canada, since recent indications are that Canada's domestic demand will not exceed its supply from established sources until the late 1980's. It argues that increased discoveries would also attenuate the need for quick development.

Staff advocates the weighting methodology originally appearing in the Department of Interior report to Congress (EP-231). This technique considers proved reserves plus 70% of probable reserves plus 30% of possible reserves. In addition, Staff argues that access to delta gas will be of considerable interest to Canada in the near future, since traditional domestic supplies will be below the total of Canadian domestic demand and exports to the United States. The issue of NEB approval of a Mackenzie Delta lateral will be discussed in the Canadian Law and Policy section of this decision.

3. Reserve and Deliverability Estimates

Arctic Gas hired D&M to do a volumetric study of gas reserves in the delta area. Classifying reserves into proved, probable and possible 1/, D&M estimated salable gas reserves from 8 Mackenzie Delta fields, as of July 31, 1975:

Line	Field or Area	Proved	Probable	Possible	TOTAL	Line
1	Adgo	78,280	58,511	111,903	248,694	1
2	Mallik	60,044	100,880	276,600	437,524	2
3	Niglintgak	315,421	146,391	195,001	656,813	3
4	Parsons Lake	531,790	538,780	413,951	1,484,521	4
5	Reindeer	5,294	5,414	7,315	18,023	5
6	Taglu	2,728,191	61,799	0	2,789,990	6
7	Titalik	10,131	48,022	123,000	181,153	7
8	Ya Ya	97,316	60,604	234,000	391,920	8
	TOTAL	3,826,467	1,020,401	1,361,770	6,208,638	

(MMcf at 14.73 psia and 60^{o}F) (AA-33) 2/

It is instructive to note the effect of recent drilling periods on reserve totals. The drilling from December 1974-July 31, 1975, had the effect of increasing proved reserves from 3.775 Tcf to 3.826 Tcf, but decreasing total reserves from

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1/ (1) Proved - reserves proved to a high degree of certainty for commercial production by reason of actual completion, successful testing, or secondary recovery operations.

(2) Probable - reserves defined by less well-control than proved reserves; based on evidence of producible gas and oil within the limits of structure or reservoir above known or inferred water saturation.

(3) Possible - reserves considered to be less well defined by structural control than probable reserves; may be based on electrical-log interpretations and widespread evidence of crude oil or gas saturation.

2/ All the gas included in the D&M estimate is non-associated, and a recovery factor of 80% or 85% was used for most of the fields. A shrinkage factor of 5% was employed to arrive at salable reserves. This shrinkage figure indicates liquid removal and reflects the extremely dry nature of the gas.

6.571 Tcf to 6.208 Tcf. The reserve estimates cited above have not yet been updated to reflect the most recent drilling period - July 31, 1975-June 1, 1976. Arctic Gas witness E.A. Olson testified that the main effect of this recent drilling has been to substantiate D&M's estimates in presently delineated fields. He expects much of the "probable" and "possible" reserves will be moved into the "proved" category. El Paso witness Adams could not speculate whether the actual reserve estimates of D&M would be changed by the recent drilling, but he suggested that "what will be added /to proved reserves/ will just about cover what will be deleted" from probable and possible reserves (160/26,378-370; 26,435).

Sproule and Associates, acting as consultants for Canadian Arctic, presented a reserve estimate before the National Energy Board. A comparison between D&M and Spoule, while showing some variations between fields, only exhibits a difference in proved reserves of 1/10 of 1% and a difference in total reserves of 1% (89/13,4351).

D&M, on the bases of its reserve estimates, calculated what it considers to be a conservative deliverability schedule. Based on a take of 1 MMcf/d for every 7.3 Bcf of proven, probable and possible reserves, D&M's 15-year deliverability estimates as of July 31, 1975, are (AA-33):

Year	Annual Deliveries (MMcf)	Daily Average Deliveries (MMcf/Day)	Peak Day Deliveries End of Period (MMcf/Day)	Annual Wet Gas Production (MMcf)
1	312,111	855	2,259	328,538
2	312,111	855	2,156	328,538
3	312,111	855	2,053	328,538
4	312,111	855	2,059	328,538
5	312,111	855	1,860	328,538
6	312,111	855	2,020	328,538
7	312,111	855	1,814	328,538
8	312,111	855	1,807	328,538
9	312,111	855	1,601	328,538
10	312,111	855	1,574	328,538
11	312,111	855	1,415	328,538
12	307,517	843	1,265	323,702
13	282,189	773	1,323	297,041
14	269,885	739	1,176	284,090
15	253,381	694	1,024	266,717

In addition, Arctic Gas argues that further discoveries in the delta area will support initial deliverability levels of 1.25 Bcf/d and subsequent levels of 2.25 Bcf/d by the fifth year of operations.

El Paso did not introduce an independent Mackenzie Delta reserve study. Moreover, it did not strongly contest the accuracy of D&M's reserve figures. Rather, El Paso disputes the use of the figures in the D&M deliverability schedule. 1/ Arguing that there is speculation involved even in the proved reserves and that recent drilling has not been encouraging in developing additional reserves, El Paso maintains that only proved reserves from the Taglu, Parsons Lake and Niglintgak fields should be employed in a deliverability schedule. The result is a significant reduction in delivered natural gas, based on a 20-year schedule (EP-241):

Schedule Showing a Comparison of El Paso Alaska and Alaskan Arctic Gas Forecast of Salable Gas Production from all Fields or Areas from which Alaskan Arctic Gas Proposes to Purchase Gas in the Mackenzie Delta Area, Northwest Territories, Canada

All Volumes in M^2cf per Day at 14.73 psia and 60° F.

Year	El Paso Alaska Forecast: From Areas with *Sufficient* Reserves to Warrant Pipeline Connections	El Paso Alaska Forecast: From Areas with *Insufficient* Reserves to Warrant Pipeline Connections 2/	El Paso Alaska Forecast: Total	Alaskan Arctic Gas Pipeline Forecast
(a)	(b)	(c)	(d)	(e)
1	487.4	34.6	522.0	855.0
2	487.0	34.6	521.6	855.0
3	486.7	34.6	521.3	855.0
4	486.4	34.6	521.0	855.0
5	486.2	34.6	520.8	855.0
6	486.0	34.6	520.6	855.0
7	478.6	34.6	513.2	855.0
8	470.9	34.6	505.5	855.0
9	461.6	34.6	496.2	855.0
10	455.3	34.6	489.9	855.0
11	449.1	34.6	483.7	855.0
12	443.7	34.5	478.2	843.0
13	437.8	34.0	471.8	773.0
14	415.7	32.3	448.0	739.0
15	389.1	30.8	419.9	521.0
16	363.6	29.4	393.0	-
17	339.0	27.9	366.9	-
18	310.3	26.0	336.3	-
19	284.3	23.9	308.2	-
20	259.7	20.1	279.8	-
Beginning Reserve, bcf	3575.4	251.2	3826.6	6208.6
Production For Period, bcf	3025.0	233.3	3328.3	4482.6
Remaining Reserve, bcf	480.4	17.9	498.3	1726.0

Note: Alaskan Arctic Gas Pipeline Forecast of Salable Gas Production is based on proven, probable and possible reserves for a fifteen (15) year period.

1/ See next page.

2/ See next page.

4. Discussion

a. Existing Fields

Arctic Gas, Foothills and Staff have shown that "proved," "probable" and "possible" reserves from the 8 presently existing fields must be considered in these proceedings. Development drilling activity in the two most recent drilling periods has served to shift reserves to the "proven" classification, and there is every reason to expect this trend to continue. Moreover, the process will likely accelerate as drilling, spurred by a Mackenzie Delta pipeline certification, increases. Finally, it is unreasonable to include only 3 fields, as El Paso suggests, in the determination. Many of the other fields have sizable total reserve estimates, and there is a substantial likelihood that as development continues, additional reserves will be proved and these fields will be tied into the system.

In assessing probable and possible reserves, a conservative weighting methodology, endorsed by Staff and described in EP-231, should be employed. This technique assumes, by its very nature, that not all "probable" and "possible" reserves will become proved. As stated supra, the weighting method discounts probable reserves by 30% and possible reserves by 70%. In the instant case, based on D&M estimates of July 31, 1975, the totals are 3.83 + 0.70(1,020,401) + 0.30 (1,361,770) = 4.95 Tcf. Using a rate-of-take of 1:7300, initial deliverability is 0.68 Bcf/d.

b. Future Supply

The eight Mackenzie Delta productive fields or areas discovered through July 1975, reflected in the D&M study, will be capable of delivering about 0.7 Bcf/d by the time Canadian Arctic's operations commence. As noted above, on a contract

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1/ (Footnote from previous page)

El Paso makes the argument the D&M deliverability schedule is defective in that it simply assumes a contract rate-of-take of 1:7300, whereas the El Paso schedule is based upon the capability of the fields to produce. The fact is that both schedules show deliverability consistent with the contract rate for a considerable period of years before decline sets in.

2/ (Footnote from previous page)

El Paso does not include the Reindeer field under this heading, since it considered its 5.3 Bcf of proved reserves too small to warrant a forecast of deliverability.

rate-of-take basis of 1:7300, this deliverability implies the proving up of additional reserves for a total of about 5.0 Tcf in those fields by that date.

However, it would be totally short-sighted and unrealistic, in view of the potential of the area and the long lead times involved in this project, to rest the case, as only El Paso urges, on the proposition that no additional reserves from new fields or areas can be relied upon to be forthcoming by the time operations commence, say 1982, or within a reasonable time thereafter. The record simply will not permit the conclusion that exploratory drilling activity in the Mackenzie Delta area is either on the verge of coming to a grinding halt or, if continued, will be totally fruitless.

While the Commission need not, and in the past commonly did not, look beyond the level of proved reserves in making findings respecting gas supply in every certificate case, it is apparent that there is no inflexible policy which requires one to ignore facts which strongly recommend consideration of gas supplies not yet proven. In Arkansas Lousiana Gas Co., 47 FPC 583 (1972), the Commission in fact gave weight not only to discounted estimates of probable and possible reserves in existing fields, but to the general potential of the overall province as well. In reaching its conclusions in that case, the Commission stated (at 587):

> While we share the preference of these intervenors for obtaining reserve information which is precisely measurable, we believe that the evidence in this proceeding supports the reasonable reliability of the reserve estimates. We have here exercised our judgment on the basis of the evidentiary record, and on the estimates it contains of undeveloped reserves and probable potential reserves, and, to a lesser extent, of possible potential reserves. Given the concurrence of all parties in the view that the Deep Anadarko Basin holds exceedingly rich reserves-on the order of 60 trillion cubic feet, given the Examiner's scrupulous assessment of the reserves dedicated to Arkla, field by field, and given, finally, the fact that the days of abundant supplies of natural gas are, at least for a time, behind us, we think it reasonable to grant a certificate based upon the Examiner's reserve conclusions in this proceeding.

Likewise, in the circumstances of this proceeding, an attempt must be made to reach an estimate of likely future deliverability from reserves now proved and those to be proved over the next several years. Such exercise of judgment, however, must be based on evidence of what can reasonably be expected to occur. Cf. Memphis Light, Gas and Water Division v. F.P.C., 504 F. 2d 225, 234-235 (D.C. Cir. 1974.) Needless to say, where projections are based in part on reserves as yet undiscovered, reasonable expectations should be conservatively framed.

There is no challenge on the record to the assessment that the Mackenzie Delta, onshore and offshore, constitutes a major gas-bearing province with very substantial potential reserves in the early stages of exploration. D&M has estimated potential recoverable reserves in the Mackenzie Delta area out to a water depth of 36 feet in the Beaufort Sea to be approximately 50 Tcf (Item AA-H, p. 27). Foothills, in its presentation before the NEB, has estimated a somewhat lower Mackenzie Delta potential of 39 Tcf (FPL-1). Dome Petroleum, which is already drilling beyond the 36-foot depth level, has estimated upwards of 250 Tcf in its testimony before the NEB concerning potential recoverable oil and gas reserves in the Mackenzie Delta/Beaufort Sea Basin. 1/ Reasonable men must, of course, view such estimates of potential undiscovered gas reserves with great caution; but even if the least of these estimates is discounted severely, the inescapable conclusion remains that a large resource base exists and that substantial additional gas reserves can be discovered over the next several years.

The extent to which such reserves will in fact be discovered will depend on other considerations. The construction of a gas transportation system into the Mackenzie Delta will obviously have a stimulating effect on drilling in the area: this has typically been the result of the extension of marketing facilities into promising oil and gas-producing provinces. The long-term energy policies implemented by Canadian authorities, especially with respect to provision of adequate producer price incentives, will also unquestionably have substantial impact on drilling activity. While one cannot presume to advise what these policies should be, it hardly seems likely that if the Canadian government should approve the construction of a gas transportation system into the Mackenzie Delta on the basis of pending applications, it will fail to provide and maintain the regulatory climate conducive to optimum exploitation of that system. The record indicates that recent natural gas price increases in Canada have resulted in a significant increase in exploratory activity in the traditional western producing provinces. While a similar impact has not yet been perceived in the Mackenzie Delta area, the allocation of financial resources first to the traditional areas with marketing facilities in place is merely good business practice, especially in light of the long lead times involved in any Mackenzie Delta project.

1/ Dome commenced its Beaufort Sea drilling program in the summer of 1976. No results have yet been announced respecting the two wells being drilled.

This does not mean, however, that there has been a hiatus in exploratory and developmental drilling activity in the Mackenzie Delta. Drilling activity during the 1975-1976 winter drilling season continued at approximately the same pace as in prior years and is expected to meet or exceed that level in the 1976-1977 season (178/29,585-9).

As of June 1976, 73 wells had been completed in the area. The first successful gas well was completed in the summer of 1971. Prior to that time, 4 dry holes had been drilled (AA-118). In the 4-year period from the completion of the first gas discovery well to the June 1975 date of the D&M reserve study, a total of 3.8 Tcf of proved reserves had been discovered, an average rate of nearly 1 Tcf per year. If over the following 7 years, proved reserves are conservatively projected to be discovered at an average annual rate of only 0.6 Tcf (roughly two-thirds of the earlier rate), the proved reserve total would amount to roughly 8 Tcf in 1982, sufficient to support a deliverability of about 1 Bcfd on the basis of 1:7300 rate-of-take. Such conservative findings rate would result in discoveries of about 11 Tcf and would support deliverability of about 1.5 Bcfd by 1987, the fifth operational year. Total findings of this magnitude by 1987 would require discovery by that time of about 28% of the 39 Tcf potential reserves estimated by Foothills before the NEB, or slightly more than 20% of the D&M potential estimate.

The foregoing considerations support the finding of a reasonable likelihood of Mackenzie Delta deliveries of not less than 1 Bcfd in the first year of operations and 1.5 Bcfd in the fifth year. In reaching this conclusion, no weight has been given to the much more optimistic estimate of potential reserves made by Dome Petroleum. Nor does the conclusion depend upon a substantial acceleration in drilling activity which can be expected to occur with approval of a transportation system: if the average exploratory level of prior years is maintained, the necessary reserve additions can be achieved even if the average annual findings rate declines. Further, these deliverability figures reflect the taking down of reserves at a rate-of-take of 1:7300, although the evidence shows that faster rates of take could be achieved; thus any temporary shortfall in findings could be offset by higher depletion rates.

IV

CONSTRUCTION AND GEOTECHNICAL

It must be understood at the outset that none of the applicants proposes to build a system based upon a new technology. The basic proposals are to use known technology and to adapt, "scale-up," modify or improve that known technology. While in many instances the very nature of "scaling-up" creates engineering and construction uncertainties, and while some of the equipment may not yet be commercially available, the key consideration is that no equipment or processes need be developed from scratch in order for any of the projects to be viable. This is not to say that the construction programs and techniques often will not be at the very edge of the applicant's present ability to build its system or to mitigate unavoidable environmental damages. This is true, for example, of considerations as diverse as construction by all three applicants of buried, chilled gas pipelines in permafrost, revegetation of alpine or coastal tundra, fabricating a ditching machine or snow machinery equipment larger than any built before, achieving novel, higher fuel efficiencies in gas liquefaction, or building 165,000-cubic meter LNG ships. The evidence shows, however, that notwithstanding whether a construction plan is cost-effective in the time frame allowed, it is technically feasible to build these pipeline systems and to do so in an environmentally acceptable manner. The purpose of this section is only to examine the major construction and technical problems associated with each proposal. Construction and operating costs, while incidentally discussed here, are discussed in the next section.

The first argument of each applicant, of course, is that the others have insufficiently studied the geotechnical ramifications of their construction proposals, have inadequate knowledge of the environment to permit effective engineering and construction mitigation, and lack experience with new technology. They argue that, as new information is developed, there is the likelihood that substantial modifications of their competitors' plans will have to be made, that some of these modifications will result in a slippage of time schedules, and that most changes will require additional capital costs. Each, of course, claims that its own project suffers no such impairment while strenously arguing the inadequacy of the other proposals. All three projects will build some pipelines under wintertime conditions, but only Arctic Gas, Alcan and El Paso argue, will not be able to do so efficiently and effectively because its schedule requires continued construction through each of the winter months. Alcan argues that its 1250-psi pipe can be run at 1440 psi, although it made no such case, and criticizes Arctic Gas and El Paso, whose design also calls for operating pressures in excess of those currently in practice, for not using as conservative a design as Alcan. Both Arctic Gas and El Paso attack Alcan for its almost superficial showing on both geology and the environment and state that there will be substantial delay before critical underlying drilling and field studies can be undertaken, much less analysis of the results. Arctic Gas tars El Paso with the same criticism for that portion of El Paso's route through the Chugach National Forest and for the lack of in-depth studies, for example, as to the effect of putting heated cooling water into Prince William Sound. And so on and so on. These type of arguments insinuate themselves through virtually every technical issue, not just the construction and geotechnical matters addressed in this section, and the decision as to each must be considered not only as to its feasibility but also as a part of the reliability of the construction schedule proposed and the cost associated therewith.

One other matter must be addressed here. None of these applicants wants to build a pipeline which is technically poor, environmentally unsound, and so costly that the merchandise being transported is outpriced in the market place. They would not deliberately build, even if the regulatory authorities and the lenders would let them, an unworkable transport system useless for all tasks except bankrupting the sponsors.1/ The geotechnical criticisms of each of these applicants' plans must be leavened with the understanding that while there are substantial differences among the experts and engineers, their motives were to design workable projects which they individually believe can be accomplished within the state of their art. The dispute, in other words, is among competent engineers and scientists, and while only a Pollyanna would blindly adhere to their views, ignoring their planning and merely suggesting that they will be "surprised" by unanticipated events is unwarranted.2/

Nor can the following section be viewed as the final disposition of those engineering issues relating to technical specifications of ships, pipe, seismic design, etc. The appropriate regulatory authorities having expertise and the legal mandate to authorize particular modes of construction (whether it be 165,000-cubic meter ships, approved by the U.S. Coast Guard or the Bureau of Ships, or new specification of pipeline, approved by the

1/ See Financial section *infra*.

2/ References to the Titanic to describe the "super-ditcher" (203/34,891) or suggesting that all work stops during icefogs when it does not (203/34,785) are the prejudices of the lawyer and do not reflect the planning of the engineers. The Titanic was also used to describe LNG ships (51/7602).

Department of Transportation) will make the final decision as to the propriety of utilizing this technology. The discourse here is to its technical feasibility on the basis of the evidence submitted and whether each applicant has made its case that the technical aspects can be accomplished.

As already stated, each proposal carries on its back its own load of burdens and troubles. Each project will be analyzed, therefore, on those substantial construction and geotechnical problems associated with it.

A. Permafrost

Common to all three applicants are the significant difficulties associated with construction through permafrost and discontinuous permafrost areas, whether in the summer or winter. While the discussion below is not intended to be a primer on the subject, it is intended to give an indication of the level of concern for construction difficulties.

First, permafrost refers to the state of the soil -- frozen or unfrozen -- and not to the composition of the soil. Permafrost is defined as ground that remains frozen (below 32°F.) for the entire year.[1] Discontinuous permafrost refers to areas where some ground is continually frozen and some is not and, in so-called "fringe" areas, the frozen areas could change over a period of years. The existence of ice is unimportant for definitional purposes, but its presence or absence is of extreme importance to Arctic construction. (See ST-26, pp. 74-79.) In the far north, where the summers are short, most of the earth's ground remains frozen all year except for the active surface layer which may thaw only to a depth measured in inches. See, *infra*, snow-road discussion.

From a pipeline engineering and environmental point of view, the prime consideration is whether the soil in an unfrozen state is thaw-stable or thaw-unstable. In either the permafrost or discontinuous permafrost area, construction of a hot gas pipeline, the usual mode of pipeline construction, could cause thaw settlement if the ground were not thaw-stable, and the construction of a chilled gas pipeline would avoid thaw settlement as a problem in the permafrost area. Using that same terrain for a chilled line, however, could present frostheave problems. The very soils sought for a hot oil pipeline, for example, would often be the ones to avoid for a chilled gas pipeline. Degradation of the vegetative covering in either permafrost area, moreover,

1/ See ST. 24, a glossary attached to the DOI-FEIS.

can cause thermokarsting[1/] and this may result not only in environmental damage but also in instability of the pipeline.

Since thaw settlement problems have been encountered in pipeline construction in the past, it is the "frost heave" phenomenon which is most significant new problem from an engineering point of view. In the most simple scenario, certain soils, primarily in the discontinuous permafrost zone, will permit water migration through the soil to the buried pipe. The pipe has chilled gas, below 32°F., and as the water migrates to the pipe, it freezes when it encounters the frost bulb formed around the chilled pipe. If conditions are conducive, ice lenses would form around and under the pipe, causing frost heave. Frost heave theoretically could push the pipe out of the ground or buckle the pipe. Summer construction presents different concerns, since the ditch may be subject to deterioration by melting if in ice-rich soils. Pipeline construction requirements, of course, may differ depending upon water migration and the engineering to avoid frost heave, including, among other items, prevention of water migration at each point and the channelling, overburden, and avoidance of certain soils. Arctic Gas will encounter about 250 miles of soils susceptible to frost heave, Alcan 100, and El Paso between 50 and 100.

The phenomenon was addressed in the applications, in the impact statements, and by many geological and construction witnesses. Substantial time has been devoted throughout the hearing process to pinpoint the effect upon the pipeline and whether the Arctic Gas research effort, the primary research effort undertaken in the whole area, gives sufficient confidence that frost heave can be overcome. All of the experts believe it can be done, but the final configuration of ditch design and specific engineering for each condition on each pipeline section affected has not been completed.

B. <u>High-Pressure Pipe</u>

Arctic Gas, El Paso and Alcan all propose to operate their pipeline systems at maximum pressures substantially in excess of levels currently in use in the industry. Nothing in the record suggests that these higher operating pressures cannot be achieved with pipe adequately designed for the purpose. This is not to say, however, that Alcan can reliably and economically achieve its suggested performance at 1440 psig with pipe ostensibly selected to operate at a maximum pressure of 1250 psig. It is found that

1/ Progressive deterioration of the surface until a new equilibrium of heat exchange is established. (See also St.24.)

the operating design pressures are logical extensions of existing pipeline operations and can be achieved here by those applicants making proposals to operate at the higher pressure.

C. Arctic Gas - Technical Feasibility and Construction Schedule

As noted previously, the Arctic Gas proposal calls for 4,500 miles of pipeline extending from Prudhoe Bay through Alaska and Canada to termination points in the lower 48 states. One hundred ninety-five miles of the pipeline would lie in Alaska and would run along the northern coastal plain and, to a significant extent, through the Arctic Wildlife Range. At the Canadian Border, the Alaskan portion would interconnect with the Canadian line, which would thereafter merge with the incoming Richard's Island line at Tununuk Junction in the Mackenzie Delta and continue south to Caroline Junction, Alberta. Eastern and Western legs would then transport the gas to points of interconnection with facilities of PGT and Northern Border at the U.S.-Canadian border The Canadian operation would span a total of about 2,300 miles. The remaining miles of pipeline would lie within the lower 48 states.

This section assesses the technical feasibility of the Arctic Gas project and the viability of its proposed construction schedule and, derivatively, its capital cost estimates. Consistent with the history of these proceedings, attention is focused throughout this section on that portion of the proposed Arctic Gas system which will run from Prudhoe Bay to Caroline Junction. Nature lays the ground rules here, and the question to be answered is whether or not, through advanced technology and proper allocation of resources, Arctic Gas can meet its objective without violating these rules. Section 1 is devoted to a general review and evaluation of steps undertaken by Arctic Gas to minimize risk in connection with the construction and operation of its pipeline. System design is considered first in an effort to gauge system reliability. Thereafter, Arctic Gas' construction schedule is scrutinized in an effort to test the hypothesis of Green Construction Company that completion of this portion of the Arctic Gas project will be delayed by 2 years or more.

Arctic Gas' planned use of snow roads for winter construction has attracted criticism from various camps. Concern has been voiced as to the technical feasibility of these roads, given the task to be accomplished and the time allowed, and as to the lasting detrimental effect, if any, which the snow-road operation may have on the Arctic tundra. The issues are complex and merit special treatment; accordingly, a special subsection (Section D, *infra*) has been reserved for this purpose.

Similarly, Arctic Gas' proposed crossing of the Mackenzie Delta raises specific questions, both environmental and geotechnical, which pertain to that segment of the project alone. Those questions will also be addressed in a separate subsection (Section E, infra).

1. System Design and Maintenance

If the design of the system is not technically feasible, the construction schedule is irrelevant. The 48-inch pipe which Arctic Gas intends to construct between Prudhoe Bay and Caroline Junction will be the largest ever used to transport natural gas, and the 1680 psig of maximum operating pressure which Arctic Gas intends to use to force the gas through the pipe will exceed the thrust of any gas pipeline now in existence in North America. In addition, the Arctic Gas pipeline will be traversing environmentally sensitive areas of permafrost, discontinuous permafrost, and southern fringe between Prudhoe Bay and Caroline Junction. Special care must be taken, therefore, to insure both the integrity of the terrain and the delivery system involved. The record demonstrates that Arctic Gas has met its responsibility in this respect. Arctic Gas has conducted several experiments to verify the efficacy of its plan to chill its pipeline below 32°F., as necessary, to maintain compatibility with the soil (19/2919-2932). Arctic Gas has developed and tested a model to predict frost heave (154/25,305; 218/38,101-102) and is actively engaged in research aimed at perfecting methods by which the effects of this phenomenon can be controlled (246/42,917-920; 154/25,304-305; Exhibit AA-12; Slusarchuk, p.6).1/ Arctic Gas has conducted extensive stress analysis (173/28,432-448) and has developed an impressive array of design criteria by which to condition the line to endure foreseeable stresses and strains (173/28,440-441). Arctic Gas has consulted a seismic engineer and has been advised as to the level of seismic resistance which should be built into the pipeline and related facilities (Exhibit AA-12, Newmark, p.3). Finally, Arctic Gas has developed design techniques, including revegetation, for controlling drainage and erosion along the backfill mound (AA-Q, Section II.D., p.19 and Section II.E., p.39; Exhibit AA-12, Dabbs, pp.4-10).

Of the myriad of points raised by the competing applicants in these geotechnic briefs, several points merit individual treatment:

1/ For example, Arctic Gas has determined that, where the chilled pipeline undercuts flowing stream beds or intercepts underground aquifers, insulation will be used to keep the frost bulb from growing too large and thereby causing the invasion of frost-susceptible soils (20/3140; 19/2980).

a. Crack Arrestors

Arctic Gas' 48-inch O.D. pipe will be operated at 1680 psig and at a stress level of 0.72 times specified minimum yield strength (SMYS). The unprecedented combination of forces at work within the pipeline has led Arctic Gas to take certain precautions designed to reduce the possibility of an incapacitating fracture of the pipeline wall.1/ To begin with, Arctic Gas has included in its pipe specifications a requirement that the pipe be strong enough to absorb a defect of 6.5 inches or less without fracturing. Through inspection,Arctic Gas should be able to detect defects of much smaller size. Finally, hydrostatic testing will augment Arctic Gas' ability to locate and correct defects prior to actual usage of the line (Exhibit AA-12, Purcell, pp. 17-18; 245/42,630-42).

Recognizing that the duration of an outage will increase with the length of a fracture which does in fact occur, Arctic Gas has also taken steps to prevent fracture propagation. The danger of a running brittle fracture has been minimized by the use of steel which behaves in a ductile (flexible) rather than brittle fashion at the operating temperature of the pipeline (Exhibit AA-12, Purcell, p.18; 245/42,629). Propagating ductile fractures, although rare (245/42,649-651; 221/38/638-639; 22/38,764), are also a proven phenomenon which, in Arctic Gas' view, should be contended with. As a consequence, Arctic Gas intends to install crack arrestors at intervals of 300 feet along its pipeline to limit the length of any break (171/28/145-146). Arctic Gas' witness Von Rosenberg described this crack arrestor as a tight-fitting,

1/ To put this issue in perspective, Mr. James Wallbridge, an Alcan witness, stated that the ductile fracture propagation characteristics of high-pressure, large-diameter pipelines is at the edge of metallurgical research. There are no "correct" metallurgical answers. Mr. Wallbridge believed the possibility of this type of fracture, however, was so small that he would not recommend designing against it (252(2)/ 44,230). Nevertheless, the parties forged ahead with evidence and rebuttal on the subject. The fact is that use of crack arrestors is a conservative answer to the possibility of this type fracture, and crack arrestors were also used by El Paso. The ultimate decision presumably would be made by the Department of Transportation's Office of Pipeline Safety which will decide if they are needed and if they should be installed.

welded sleeve around, but not welded to, the pipe (245/42,630).1/

Testimony of Arctic Gas' witness Price indicates that crack arrestors increase stresses by the equivalent of 8,000 psig (245/42,634). This increase produces a deleterious effect on the ability of the Arctic Gas line to withstand flexual stresses (caused by frost heave), in that it exposes the pipe to wrinkling at a lesser degree of curvature than would otherwise be the case (245/42,635). Alcan submits that this phenomenon is per se detrimental, in that it imposes additional design constraints. According to Dr. Price, however, the degree of curvature necessary to cause wrinkling of the pipe with crack arrestors attached is substantially beyond the maximum allowable curvature under preliminary Arctic Gas design criteria (245/42,635), thus obviating the need for design modification.

Alcan further argues that the increased stress attendant to the use of crack arrestors can be a source of fracture initiation or reinitiation. In support of its position, Alcan refers to a burst test conducted by Arctic Gas in which an artificially induced fracture was reinitiated on the far side of a crack arrestor after the pipe had been thrown out of the ditch due to the tremendous pressure release caused by the rupture (222/38,788).

Be that as it may, a review of the evidence disproves the theory that crack arrestors tend to exacerbate propagation of a ductile fracture. On the contrary, crack arrestors performed efficiently in three other burst tests documented on the record. In two of these, the fracture was initiated only 12 feet from the crack arrestor and travelled toward it at maximum speed (245/42,630).2/ The unsuccessful test described above merely demonstrates that crack arrestors are not foolproof, i.e., reinitiation may occur despite the presence of an intervening crack arrestor. To draw from this test the inference that crack arrestors do not serve a useful function -- indeed, that they are somehow detrimental -- is patently erroneous.

1/ As stated earlier, El Paso also proposes to install crack arrestors, but its design is a ribbon of steel around 5 feet of pipe at several hundred-foot intervals. Somehow Alcan interest only seemed to run to Arctic Gas' design, although if El Paso's is a provable design, it would be used by Arctic Gas.

2/ These tests were conducted at about 68° (245/42,689), admittedly above the temperatures at which these arrestors would be functioning in the Arctic. The rates of velocity experienced in these two tests (1150 and 1500 feet per second), however, were significantly higher than that (1000 feet per second) experienced in the third test, which was conducted at a representative lower temperature (Id.).

b. Seismology

Alcan asserts that Arctic Gas' presentation has been deficient in its treatment of seismic risk, noting that Arctic Gas' evidence on this subject was sponsored, not by a seismologist but by a seismic design engineer whose expertise qualifies him to design against known risk but not to determine the nature of the risk in the first place. The record discloses, however, that Arctic Gas' witness Newmark's design criteria were established on the basis of credible historical records showing seismic hazards along the route (Exhibit AA-12, Newmark, p.3). Although the North Slope is not known to be seismically active, evidence presented in DOI's Exhibit ST-27 shows a potential for earthquake activity of Richter magnitude 5.5 along the Alaskan North Slope, 6.5 in the vicinity of Fort McPherson, Northwest Territories, 7.0 along the Canadian North Slope between MP285 and MP291, the western edge of the delta crossing, and 6.0 along the Canadian main line between MP410 and MP655, a distance of some 245 miles.1/ These are basically moderate values, particularly when compared to logarithm values of over 8 in Southern Alaska. In light of the difficulty in pinpointing epicenters of past earthquakes and the dearth of knowledge as to which faults may be seismically active and which inactive, it is not possible to find that any section of the Arctic Gas project is totally risk free. By the same token, Dr. Newmark's seismic design is zone-specific, rather than site-specific and appears to make more than adequate provision for all contingencies. His uncontroverted testimony indicates that the degree of seismic safety of the Arctic Gas system exceeds that which is currently required for newly constructed pipelines (Exhibit AA-12, Newmark, p.5).

Alcan also refers to the observation in Exhibit ST-27, p.793, to the effect that seismic shocks could cause some soil liquefaction in the eastern delta region. As discussed in the cross-delta construction section, infra, soil testing has shown the probability of liquefaction in this area to be slight at best.

In its Geotechnical Reply Brief, El Paso suggests, as an aside, that the integrity of all three systems would be critically and equally affected by a seismically induced failure at Gravina Point, the argument being that Gravina Point failure would likely be accompanied by a failure at the Valdez oil terminal, the effect of which would be to halt production of oil and associated gas at Prudhoe Bay. Whatever the degree of parity between the seismic risk at Gravina Point and Valdez, it is nevertheless clear that, following a seismically caused mutual

1/ Richter scale: The range of numerical values of earthquake magnitude. In theory there is no upper limit to the magnitude of an earthquake, but the strength of earth materials produces an actual upper limit of slightly less than 9. The scale is logarithmic (ST 24, p.28). See also ST51, pp. 26 and 27.

outage, use of the Alyeska equipment at Valdez should be restored more expeditiously than use of the highly more sophisticated equipment at Gravina Point. El Paso's risk is therefore paramount.

c. Off-Season Repairs

Dual pipelines are installed at river crossings and the entire Shallow Bay crossing to avoid outages and the need for immediate repair if an accident should occur. (See also infra, **Cross-Delta discussion.) The likelihood of a pipeline break** is not great, however, and statistically, the chance of a pipeline break is calculated on a conservative basis of one break every 10 years or so on that pipe in permafrost areas (170/23,081).

Spring or summer repair may arise, however, in an environmentally sensitive locale along the Arctic Gas pipeline, and, if it were to occur, it would probably occur during those seasons of higher thermal activity (170/28,081). The worst case situation is a break on a non-dual pipeline section in the permafrost area.1/ Extensive evidence has been presented to show that, through system design and use of sophisticated transport equipment, Arctic Gas has kept to a minimum the chance of permanent geological damage or extended interruption of supply, even if the unlikely break should occur. As noted supra, crack arrestors in all likelihood will be placed at 300-foot intervals along the pipe to limit the length of any break and thus the number of lengths of replacement pipe necessary. Necessary personnel, thought to number about 50 or 60 for a significant repair operation, could be obtained from the operating and maintenance staff of the pipeline and/or contractors elsewhere and flown to location within a day (171/28,142). Arctic Gas has several helicopters available to transport men and small equipment to the rupture site (170/28,082). Heavier equipment, including sideboom tractors and a crane for raising and lowering pipe and backhoe and blade vehicles used for excavation and backfilling, could be transported to the scene via low ground pressure (LGP) vehicles or air cushion vehicles, depending upon the terrain to be traversed (170/28,082-083). The repair operation would, in the most extreme case, be completed within 1 week (Id.). Mr. Dau admitted that use of such vehicles would be expected to cause some damage to the tundra, but he also stated that the damage would not be irreparable (171/28,146).

d. X-70 Pipe

El Paso admonishes that the X-70 grade pipe which

1/ If the break occurred during the late spring or summer, it would be during a period of lessened consumer demand.

Arctic Gas proposes to use in constructing its pipeline above the 49th Parallel has not yet been approved for use by the Department of Transportation's Office of Pipeline Safety, as required under the Commission's regulations before a certificate can be issued. The pipe, of course, represents no new technology in metallurgy or manufacture. El Paso's observation is correct but not determinative. It is clearly the responsibility of the Administrator (under the Alaska Natural Gas Transportation Act) or this Commission to insure that the pipeline ultimately approved for use in transporting Alaskan Gas to the lower 48 states meets applicable safety standards, and any successful applicant will be held to such standards.

2. Construction Scheduling

The Arctic Gas construction schedule contemplates a 6-year period between receipt of initial governmental authorization to construct its project and commencement of gas flow. Actual construction would not begin until the winter of the fourth year and would be completed by the end of the sixth winter. Under the Arctic Gas Plan, the Alaskan and Canadian portions of this construction will be carried out by nine "spreads," a spread being a unit of manpower and equipment which is given responsibility for fabricating one or more stretches of pipeline and related facilities. The spreads are denominated A through I and are shown by geographical assignment in Exhibit AA-83. The manner of movement of a spread is perhaps best illustrated in Exhibit AA-132, Figure 18 (using Spread A as an example). Construction on portions of the Arctic Gas pipeline below Tununuk Junction will proceed throughout the three construction winter and two intervening summer periods, while the North Slope portion of the pipeline (above Tununuk Junction) will be laid wholly within the final winter period. The North Slope portions will be constructed by six spreads (three in Alaska, three in Canada) working simultaneously, each with a seasonal goal of some 65 miles of pipeline. These six spreads will have spent the preceding 2 years working on portions of the Arctic Gas line below Tununuk Junction.

No one who has heard or read this record would believe that winter-construction--October to March--in the Arctic is a picnic. Arctic Gas construction in the Arctic will occur only in the extended winter, characteristic of which are wind-chill factors sometimes exceeding -100°F. and prolonged darkness (Exhibit ALA-2, pp. 13-15, Exhibit ALA-12, pp. 7-12; / 14,890-894; / 13,082-086; Exhibit ST-19, pp. 62; 223). The record contains extensive testimony showing the relative success, or lack thereof, of some winter construction efforts in other cases and worker capabilities in general (34, 569-573; 34/515-534; 34, 877-878; 34, 555). Arctic Gas claims that building on prior experience of others and its own research, coupled with planning to reduce surprises, will permit it to meet construction schedules under these harsh conditions.

Arctic Gas' heavy reliance on winter construction, it is argued, subjects it to billion-dollar risks in the event of construction delay,1/ especially if that delay occurs in connection with Arctic Gas' North Slope construction during the third and final winter period. Recognizing this liability, Arctic Gas, in rebuttal testimony and exhibits introduced into evidence on October 12, 1976, revised its construction budget upward by about $210 million (Exhibits AA-130, 131). This capital cost increase was assigned to facilities and activities designed to enable Arctic Gas to meet its construction deadlines in Alaska and Canada (Id.). Arctic Gas' witness Dau also made clear Arctic Gas' willingness to incur additional costs ($118,000,000) in order to avoid delay but submitted that, for the most part, this would be unnecessary (233/40,530-549).

Arctic Gas' ability to complete its project according to schedule is determined by two variables: the number of working days available and the ability of each spread to achieve its assigned productivity rate. The number of days available is briefly discussed below in connection with welding and is more comprehensively treated in the Snow Roads subsection to follow. The ability of a spread to achieve its productivity rate depends upon Arctic Gas' ability to move supplies and equipment to the construction sites and the ability of the construction spreads to expeditiously dig and fill the pipeline ditch, lay and weld the pipe, and move the overall operation from one point to the next along the route. The record contains substantial evidence to show that Arctic Gas will be able to carry out each of these phases in timely fashion and so complete its project on schedule.

1/ Green Construction is not a disinterested "expert" as represented by El Paso (e.g. Rebuttal Economic Brief (22)). Among other things, Green is a participant in boosting Alaskan develop-development (166/27,164). The opportunity to bid on construction of 800 miles of pipe if El Paso wins, as against 180 miles for Arctic Gas, cannot be totally dismissed either. "Disinterested" is too strong a word to describe its alleged impartiality.

Green estimated that 2 years' delay would cost on the order of $2.5 billion additional, this amount being primarily attributable to the capitalized cost of AFUDC (Ex. EP-237, p. 65 and EP-267, Sheet 1 of 4; 166/27,156; 183/30,744). The method of figuring the delay, moreover, was designed to maximize the penalty for noncompletion in a given year by assuming that no mitigative measures could be taken in the year of occurrence and by assuming that delay was always cumulative -- a delay in the first year was tacked on at the end and no credit was given that the delay would be made up in the next construction season. The general limits of the risk analysis is discussed in the next section.

a. Risk Analyses Criticism

Some 44 pages of the El Paso Reply Economic Brief are essentially a review of the Arctic Gas construction schedule and logistics quantitative risk analysis of the Arctic Gas project performed by Green Construction, in conjunction with Decision Sciences and Pritsker and Associates, and presented in Exhibits EP-237, EP-255, and EP-267. The purpose of the earlier studies, which were commissioned by El Paso, was to demonstrate the potential for failure (defined as late completion, later converted to cost), of the Arctic Gas project in view of Green's criticisms (pertaining, inter alia, to camp moves) in Exhibit EP-236. Risk analyses, however, are only as valuable as the assumptions upon which they are predicated. As will be hereinafter demonstrated, the assumptions upon which Green based its risk analyses for Arctic Gas have been largely disproven on the record. Consequently, little if any weight can be given the results reflected in these analyses. 1/

Similarly, only limited reliance can be placed on the so-called risk analysis presented by the State of Alaska in Exhibit EP-239 and the risk assessment contained in the DDI Title II Study, Exhibit EP-231. Both exhibits are based upon generalizations which were made before Arctic Gas had the opportunity to explain its original construction plan on the record. Neither exhibit considers the effect of Arctic Gas' later decision to raise its capital cost estimate upward by a quarter of a billion dollars (Exhibits AA-130 and 131: 233/40,530-531) and/or its announced willingness to commit another $119 million on two additional third-year construction spreads, if warranted, in order to stay on schedule (233/40,544; 40,549). It is not necessary to go very far into EP-239 to see its bias, e.g., it gives El Paso a lower risk for blasting going through the mountains than Arctic Gas on the plain (93/15,018) and a lower risk on knowledge of subsurface data, even after admitting that El Paso has to tunnel through mountain passes where El Paso never made a test boring. The State's statement "that its probative value is more limited than one would wish" (98/15,098) is a gross overstatement of its exhibit's value.

b. Logistic Build-up

Arctic Gas plans to barge most of its equipment and supplies to stockpile sites prior to the commencement of the construction period and states that air support will be available

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1/ While the risk analysis is found wanting for the task argued for it on brief, as indicated elsewhere it had sufficient validity to convince Arctic Gas to revise its logistic and construction plans.

to fly in perishable goods and essential supplies and transport workers to and from the vicinity (233/40, 541). Barging to Alaskan staging sites (Prudhoe Bay, Camden Bay, and Demarcation Bay) would primarily originate in Seattle (22/3376; 3368). Barging for the Canadian sites would originate at Hay River, Northwest Territory, 1/ and move north down the Mackenzie River (22/3376).

El Paso questions the sufficiency of Arctic Gas' plans for transporting material to construction and/or repair sites along the Arctic Gas route. Specifically, El Paso suggests that (1) Arctic Gas will not be able to procure enough properly designed tugs to facilitate supply barging along the Mackenzie River in the time available, and (2) in any event, winter freezing limits Mackenzie traffic to 4.5 months a year and prohibits use of the route around Point Barrow, through the Bering and Beaufort Seas, to the Alaskan staging sites in all but 6 to 8 weeks of the year. If the barges are delayed, it argues, Arctic Gas could lose a full construction year.

El Paso's position is based on certain statements, highly speculative in nature, made by Arctic Gas witness Dau early in these proceedings. At 23/3421-22, Dau estimated that it may take up to 2 years to acquire tug and barge equipment for the Mackenzie River once authorization for the project is obtained, but he saw no problem in meeting this schedule. It appears that the adverse effects of any such delay in procurement could be overcome by proper planning, including adjusting the barging schedule to maximize the use of barges in later stages of the construction project. (See 233/40,541.) 2/ Similarly, witness Dau's recognition of the seasonal limitations of the Bering and Beaufort Seas and Mackenzie River (22/3369-3370) is tempered by his ensuing testimony to the effect that, should waterway freeze-up interrupt movement of supply, there are alternate, more expensive and certainly less desirable, means of transporting material to the stockpile sites. Regarding the Alaskan portion, witness Dau advises that barge traffic could utilize the south coast of Alaska, whence tonnage could be off-loaded, moved by rail to Fairbanks, and thereafter hauled by truck up the Alyeska road to Prudhoe (22/3371). Freeze-up of the Mackenzie

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1/ The ocean port for Hay River would be Vancouver, B.C. Overland transportation would be by rail (22/3376).

2/ This issue is similar to one raised as to whether Arctic Gas or the Canadian Pacific Railroad would pay for the additional flatcars to transport pipe to Hay River.

River could be overcome, if necessary, by trucking supplies, including pipeline, north from Hay River to Fort Simpson via all-weather road and from there utilizing winter roads as far as Inuvik, in the Mackenzie Delta (22/3371). Little reliance can be placed upon using the Mackenzie Highway, which is currently under construction to Fort Goodhope, or the Dempster Highway from Whitehorse to Inuvik, completion of which appears to have been stalled indefinitely. Arctic Gas recognizes this and has revised its original construction plan accordingly (Exh. AA-130; 233/40,530-531).

All in all, there is little reason to believe that Arctic Gas will be unable to meet its logistic build-up schedule prefatory to each winter construction season. Proper use of barges would reduce air support to the tactical use Arctic Gas projects and would not require the armada of airplanes marshalled by Green in its criticisms.

c. Construction Camps

Arctic Gas intends to use several types of construction camps, sized and equipped according to the function they are designed to serve. Camps will be of modular construction, and thus the configuration of each specific camp will depend on precise project requirements. Erection of camps will simply require the placement of the prefabricated modules on a granular pad. When no longer required at a given location, the modules will be moved to a new camp site. 1/

For preconstruction activities, small camps designed for 10 to 50 workers will be used. Depending on the function being served, the modules will be designed to be transported either by all-terrain vehicles, helicopters, barges or sleds. The typical 24-worker camp, for example, will have three bunkhouses, each about 10 feet by 40 feet, set on blocks and attached to each other by knock-away panels (to prevent spread of fire). A washroom, kitchen-dryer, and water treatment-storage-generation equipment facility is also attached to the bunkhouses. Out buildings for waste disposal, water, office and fuel round out the physical plant (AA-Q, Fig. II F-15).

1/ A portion of Five Mile Camp was being moved at the time of the Official View, and there was no visual appearance that unbolting sections with quick disconnection of utility lines would present any more problem for Arctic Gas.

For site preparation, materials receiving and maintenance station construction, intermediate-sized camps, which are designed for crews of 50 to 200, will be required. It is anticipated that these camps will eventually form part of the camps devoted to major construction activities, infra. Camps of this type will be served by the coastal barge system, snow roads, helicopters or fixed-wing aircraft. A typical 100-worker camp will have three 38-person units, each about 120 feet by 30 feet, containing four 8-person bunkhouses and one 6-person bunkhouse. There will be a separate kitchen-diner unit (100 feet x 10 feet), a recreation hall and workshop area (AA-Q, Fig II F-16).

Large camps for major construction activities will be required for staging points and mainline construction. As recently revised, 1/ the Arctic Gas cost estimate provides for nine of these mainline camps, one per spread, each with a capacity to house and serve 896 persons. 2/ Additionally, each camp will be stocked with duplicate utility units (kitchens, dining facilities, water supply, power, waste disposal, etc.) capable of servicing another 896-worker camp and two 112-person sleeping complexes. These spare facilities will form the nucleus of each new camp as the mainline camp is relocated along the route (233/40,619). Each of the mainline camps' 112-person units 3/ will measure 142 feet by 103 feet and contain fourteen 8-person bunkhouses and two laundries. Two regular-duty kitchen-diner units will be located in the middle of the complex (AA-Q, Fig. II F-17). Pictures of Alyeska's camp are in EP-143.

The critical aspect of mainline construction camps is not their size, however, but the manner in which they will be moved during winter construction seasons and between seasons. Arctic Gas asserts that intra-seasonal movement of those camps can be accomplished without reducing productivity and delaying the construction schedule. El Paso disagrees, incorporating the findings of Green Construction in Exhibits EP-236 and EP-237 to the effect that loss of Arctic Gas' bed space during periods of camp relocation would cause a concurrent 50% reduction in Arctic Gas' productivity. These Green Construction studies did not, however, consider the revisions reflected in the Dau testimony and exhibits, referred to above, which were tendered for the record on October 12, 1976. Thus, El Paso on brief has failed

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1/ See Exhibits AA-130 and AA-131 and the prepared rebuttal testimony of witness Dau at 233/40,530-549.

2/ The Arctic Gas cost estimate provides for a basic pipeline contractor crew of 770 persons per spread, with a 26-worker crew for camp maintenance (233/40,539).

3/ Ten in all.

to account for Arctic Gas' addition of duplicate service facilities and the extra 112-person sleeping units which will be used in connection with camp movement. Furthermore, neither the Green presentation nor El Paso on brief has addressed either of two contingency plans developed by Arctic Gas and described by witness Dau at 233/40,532-533 and 40,545 and on ensuing cross-examination. The first of these is based on the estimate of ATCO, Ltd. and calls for additional personnel and equipment to erect and dismantle the nine camps in accordance with the Arctic Gas schedule; the projected additional cost is about $42 million (233,40,533). In the alternative, Arctic Gas would modify its scheme to provide for a total of 17 construction camps, with, inter alia, a lead time of 1 month between erection and use of each camp. Here additional cost or demand, more fully discussed infra, would be $56 million (Id.). Arctic Gas points out that it would commit these additional expenditures before risking the cost of delay predicted by El Paso under Arctic Gas' original plan. 1/ These measures effectively insure that intraseasonal camp moves will present no obstacle to timely completion of the Arctic Gas project.

El Paso advances the correlative argument that Arctic Gas' construction schedule improperly ignores the likelihood that as many as 12 early-season or end-of-season camp moves will be delayed by late tundra freeze-up or early tundra thaw, respectively. To be sure, Arctic Gas cannot control the vagaries of weather by the addition of workers or material, and there is always a degree of speculation inherent in any attempt to predict the onset of weather change. As discussed more thoroughly in the Snow Roads section, infra, however, it appears that the Arctic construction schedule, including initial erection of camps and ultimate dismantling and transport of camps at the end of each construction season, contains a statistically supported safety margin which will allow timely completion of the Arctic Gas pipeline despite shorter than normal arctic winters.

d. Welding

Under the Arctic Gas proposal, each of the six spreads operating on the North Slope is charged with completing about 65 miles of pipeline during the winter of the third and final construction year. Arctic Gas expects to accomplish this objective if it is allowed access to the tundra over a period of 145 to 175 calendar days during that winter. The likelihood of such

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1/ Amounting to some $900 million in construction costs plus $1.7 billion for AFUDC, on the basis of the 2.75-year delay predicted by Green Construction in Chart 1 of Exhibit EP-267.

a time window is great, given a mean access period of some 200 days (October 15-May 1; see discussion of snow road construction) 1/ and, of significance here, a period of 136 days for actual construction.

The construction sequence to be followed by Arctic Gas consists of transporting and stringing the pipe along the rights-of-way, bending the pipe to conform to terrain limitations, preheating the pipe for welding, setting the line-up clamp for spacing purposes, welding the pipe sections together, coating and wrapping the pipe, if necessary, tying in pipe sections, and excavating and backfilling ditches (203/34,817-827; Exhibit ST-19, pp. 33-36). In order to complete 65 miles within 136 calendar days, Arctic Gas intends to lay pipe at the rate of 0.48 miles per calendar day, 0.71 miles per working day.

It is the welding operation, and particularly the stringe-bead aspect of that operation, which is the most singular focus of the controversy on Arctic Gas' ability to lay 0.71 miles of pipe per working day. The Arctic Gas cost estimate currently provides for 86 welders and 96 helpers, including 10 graded helpers (233/40,537). After the pipe has been strung, bent, preheated, and introduced into a line-up clamp, the stringer-bead (or root pass) will be welded, to be followed by the hot-pass weld and, thereafter, the fill-and-cap welds. Finally, tie-in welders will make the tie-in (203/34,824-826). There is virtual unanimity among the parties as to the propriety of the welding techniques to be employed and the volume of electrode and, derivately, weld metal necessary to secure each joint. In dispute is, quite simply, the speed at which these craftsmen can operate.

As suggested above, it is the stringer-bead welders whose efficiency primarily controls the overall welding rate (Tr. 31,029; 31,035-036; 34,924). Four stringer-bead welders can work on one joint at a time. Arctic Gas' 0.71 miles/working day rate is predicated on the following assumptions: (1) that, under laboratory conditions, a stringer-bead welder can progress at the rate of at least 3 pounds of weld metal per hour; (2) that it takes 1 pound of metal to complete a stringer bead; (3) that, therefore, a crew of four can complete 12 stringer-beads per hour; (4) that 120 stringer beads can thus be completed in a 10-hour working day; and (5) that, at 50% efficiency, 60 welds per day will have been completed (Tr. 42,714-715). Since, using

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1/ As determined in the following section, actual pipeline construction can commence once 5-10 miles of snow road have been completed, and production of snow roads and pads can proceed at a rate of at least 0.5 mile per calendar day.

80-foot lengths of pipe, only about 48 joints per working day would be needed to complete 0.71 miles, it is clear that a rate of 60 welds a day would easily suffice. The 10 hot-pass and 50 fill-and-cap welders allocated by Arctic Gas for each welding crew are a function of this anticipated productivity of the stringer-bead welding unit. Arctic Gas represents that, if necessary, a few more fill-and-cap welders can be added to the crew (Arctic Gas Geotechnical Brief, p. 67). For that matter, Arctic stands ready to commit additional spreads to the Alaskan operation, if necessary, in order to meet its construction schedule. In so doing, Arctic Gas would draw upon the supplies and labor available from completed Canadian spreads (Tr. 40,543-4). To facilitate the welding operation, Arctic Gas plans to use mobile protective shelters, designed to span the 48-inch diameter pipe, provide suitable working space for workers, and maintain a temperature of 20^{o}F. or above (Tr. 34,655-663), thereby permitting work to proceed according to schedule despite adverse weather conditions. (See infra.)

El Paso disagrees with Arctic Gas' estimate of the amount of weld metal which a stringer-bead welder can deposit in 1 working day under relevant arctic conditions. Based on evidence presented by Green Construction, it is El Paso's position that Arctic Gas' stringer-bead welders, in their presently planned number, will be able to complete only 24 joints, or lay 0.36 miles of pipe, per working day. El Paso's conclusions are based largely on evidence supplied by the Green Construction Company, reflecting BP Alaska's Alyeska experience with gathering lines at Prudhoe Bay. Arctic Gas and Staff point out that the BP Alaska Prudhoe Bay experience is not comparable to the mainline construction contemplated by Arctic Gas. This observation is borne out by the record, wherein it is shown that the BP Alaska operation achieved what must be considered a lesser degree of efficiency because of its piecework, rather than assembly-line, nature (Tr. 34,712-734; 34,571; 40,542; 40,668-669). This was necessitated in part by the terrain and in part by the varied sizes of pipe employed in that gathering operation, an obstacle which Arctic Gas does not confront with its uniform 48-inch diameter, 0.72-inch thick pipe (Tr. 42,735-737).

In its Reply Geotechnic Brief, El Paso asserts that (1) its rate calculations did not rely exclusively on Alyeska experience but also incorporated experiences of Trans-Canada between 1972 and 1974 involving some 500 miles of 36-inch diameter pipe, which experience assertedly confirms that a stringer-bead welder can be expected to deposit less than half the amount of weld metal per day assumed by Arctic Gas; and (2) the appropriate operating efficiency factor for stringer-bead welding is 41%, which factor represents the amount per pound of welded electrode which becomes weld metal. With respect to the first point, it is found that no valid progress comparison can be made between the Trans-Canada and Arctic Gas projects, since they were constructed under different circumstances and used different crew composition (34,630; 34,637; 34,656). As to El Paso's second point, the 50%-efficiency factor assumed by Arctic Gas' witness was designed to simulate field welding rate as compared to laboratory welding rate, not the relationship of electrode used to weld metal deposited.

Recognizing that the welders should be protected, Arctic Gas' proposes to use protective shelters. The proposed shelters, although developmental in nature and largely untested (34,657; 34,827; 34,856), are not particularly novel in concept and are technologically feasible. The principal difference between the Arctic Gas shelters and those whose adequacy has been proven at Prudhoe Bay (34,544-545) is that the Arctic Gas shelters have been designed for optimal mobility. The initial shelter for a welding crew of 12 to 14 will be attached to a self-powered track vehicle (a modified Foremost Industries Delta-3 unit) which moves alongside the pipe from joint to joint. Once in place, this vehicle will lower the shelter over the pipe by means of retractable outriggers (34,655-644). An Arctic Gas witness testified that Henuset Brothers in Calgary had built and used similar shelters in 1975 (34,644). The same witness advised that Majestic-Wiley Contractors has, on Alyeska, successfully employed a tie-in welding shelter which is designed to be elevated by a side boom and transported from weld to weld (34,658-659). Arctic Gas had made ample provisions for artificial illumination to permit construction to proceed despite the darkness (34,777-782).

The degree to which the superior efficiency of Arctic Gas vis-a-vis BP Alaska will improve actual welding rates is, of course, subject to some speculation. However, it appears that Arctic Gas can improve substantially on the BP Alaska experience. Any shortfall in achieving the required minimum welding rate will be apparent early in the first arctic winter construction season, giving Arctic Gas more than ample time to effect its remedial contingency plans.

e. Trench Excavation and Backfill

Arctic Gas intends to employ a so-called " 812 superditcher" in its pipeline trench excavation. This machine is still in the design stage. Once operational, it will be able to cut a trench in permafrost soils 8 feet wide and 12 feet deep (hence the designation "812") and will have the capacity to ditch an average of 4,000 feet per 10-hour day, well in advance of the 0.71 miles of pipeline to be welded per working day (202/34,732). Technological pioneering has been required in designing the "teeth," which are to be inserted into a ditching wheel. Assisting Arctic Gas in this endeavor is the engineering firm of J.E. Rymes Engineers, Ltd. In early 1975, field tests of laboratory-tested teeth were conducted at Seebee and McPherson in Canada in granular soils considerably coarser than those to be traversed by the Arctic Gas pipeline (202/34,725-726). The subject teeth were found structurally incompetent (203/34,889, pictures AA-19). Thereafter, the determination was made that the ditcher teeth could not be efficiently welded onto the ditcher bucket, but would instead have to be cast internally into the bucket (202/34,720-722). Further research and development has proceeded on that basis. Laboratory tests have been conducted, and new field tests are anticipated in early 1977 (34,750-752). Expert witnesses for Arctic Gas and the Rymes engineering firm have testified that, with the teeth properly refined, the super-ditcher should be fully competent and available on schedule (Tr. 202/34,727, 34,731, 34,621-622; 203/34,748, 34,891).

In the alternative, Arctic Gas stands ready to achieve its construction schedule by increasing blasting and/or using existing, less-efficient ditchers (26,891-892; 203/34,749). 1/ The cost of blasting as compared to ditching is approximately double, or $60,000 per mile (203/34,748-749). Blasting would not require a significant increase in personnel (Tr. 34,749). In its cost estimate, Arctic Gas included an amount for blasting crews of up to 25 people per spread in anticipation of having to blast up to 17.1 of the 65 miles per Alaskan spread (202/34,566-567). It is found that trench excavation, whether with a fully operational 812 ditcher or more conventional methodology, will cause no significant delay in construction of the Arctic Gas pipeline.

Backfilling the trench once the pipe has been lowered in should present no significant timing problem. In order to guard against voids in the backfill (which might permit melting snow to penetrate the soil and jeopardize the stability of the

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1/ The Bannister 710 is the most sophisticated ditcher presently available. Its usefulness to Arctic Gas is subject to question, however. While it has been used in the past under severe conditions (202/34,735), it has not been used commercially in permafrost and its teeth may not be suitable. (203/34,889). In addition, it is designed to cut a ditch only 10 feet deep, which is insufficient for Arctic Gas' purposes. The performance of the 710 reinforces the conclusion that the 812 is the logical development and will perform as designed (202/34,735).

soil around the pipe), Arctic Gas must be certain that the backfill spoil has been properly compacted. According to staff witness Phukan, compaction can be accomplished by heating frozen backfill originally excavated from the trench. In the alternative, Arctic Gas might use select backfill for the bedding and padding which underlies the rest of the backfill restraining the pipe (234/40,860-863). Site granulation of excavated spoil appears less feasible (154/25,314; 25,495).

D. Arctic Gas-- Snow Roads

Arctic Gas proposes winter construction using snow roads and snow pads in permafrost areas. 1/ It argues that, if insufficient amounts of natural snow cannot be collected for this purpose by snow fencing or harvesting from frozen lakes, it will manufacture snow. New techniques of snow road construction designed and tested by it will assure stable, strong surfaces resulting in minimal environmental degradation. Arctic Gas also presented evidence demonstrating that snow roads can be built within the assigned schedule and in accordance with the estimated costs. 2/

The competing applicants, the State of Alaska, and the Conservation Intervenors collectively attack most aspects of the Arctic Gas plan, including opening dates for snow-road construction, snow fence use, snowfall patterns, snow manufacturing, water availability and surface degradation caused by vegetative mat compaction. In essence, they argue that, on the basis of past "snow road" failures on the North Slope and the huge scale of the Arctic Gas project, the applicant has neither proved it can efficiently and safely construct snow roads, nor that these roads will be effective in use. Staff concludes that the Arctic Gas snow road program will accomplish its intended result. However, it maintains that "long-lasting environmental abasement cannot be ruled out" (Staff Env. Br., 2).

Large sections of both the environmental and geotechnical briefs are devoted to snow roads. Specific arguments of all parties are discussed in the body of the discussion below and are not summarized separately. Since the key environmental criticism of Arctic Gas is its alleged inability to build snow roads when needed in an environmentally acceptable manner or to

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1/ The term "snow road" will be used to designate both "snow road" and "snow work pad," unless otherwise stated.

2/ While the Arctic Gas plan must be analyzed on its own strengths and weaknesses, it should be kept in mind that the alternative is gravel pads, involving problems of borrow sites, aesthetics, permanent accessibility, changes in thermal regime, drainage and added expense. Gravel pads are not acceptable because of both environmental costs and dollar costs.

construct a pipeline from them in winter conditions, the discussion on this issue has been made as complete as possible.

The skepticism of the detractors of the Arctic Gas plan, based as it is on interesting but not necessarily always relevant history of snow trail and snow pad use, is not convincing. Not only has Arctic Gas committed itself to considerable testing and planning of its proposal, but it has done so by actually building a test road and testing that road under wintertime conditions similar to those it expects to experience in permafrost areas. A review of all of the evidence, as set forth below, requires a finding that Arctic Gas has demonstrated, by the vast weight of evidence, that its snow road plan is both feasible and effective and can be accomplished with a minimum of environmental harm.

Water availability and effects on fish and vegetation are discussed in the environmental section of this decision.

1. Description

Arctic Gas proposes to build snow roads in all areas of sensitive permafrost in order to provide access to the right-of-way (ROW), borrow pits, stockpile sites and wharves, and to provide a traffic and working lane along the working side of the pipeline ROW. In general, snow roads will be used in areas north of 65° Latitude.

Arctic Gas has estimated that it will build 915 miles of snow road and work pad in sensitive permafrost areas. It disagrees with the Green Construction estimate (EP-236) of 1,150 miles of snow road and pad. Moreover, Arctic Gas maintains that most of the 643 miles of additional snow road beyond the ROW will not be required, as suggested by Green. Many of these miles will be used for moving civil construction equipment, which will take place late in the winter season without necessitating high-speed snow roads. 1/

1/ El Paso argues, for the first time on Reply Brief, that Arctic Gas has underestimated snow road requirements along the Mackenzie River and in Alberta. There is no indication given of the extent of the further necessary snow roads. It cannot definitively be found that those roads will not be needed. However, it should be noted that there are no water availability problems in this area. If El Paso's criticism is correct, the most Arctic Gas will suffer is some increased costs, which it is assumed is the point of raising the argument.

The type of snow road used in various areas will depend on the availability and characteristics of snow and other meteorological factors. Snow roads will be of two general types: used for all access roads and the traffic lane on the ROW, this type will be wide enough to accommodate two lanes of traffic (approximately 32 feet wide) and be dense enough to sustain a heavy volume of traffic; used as a working surface (work pad) on the remainder of the ROW (approximately 90 feet wide), this type will be less dense and will not require as smooth a surface, since it will be used only by slow-moving construction equipment (AA-Q). However, Arctic Gas witness Guy Leslie Williams, in calculating water requirements, used a 0.5 grams/ccm density snow for both the snow road and work pad (163/26,862). Thus it remains unclear whether both surfaces will indeed have the same density, or if not, which surface will have the 0.5 grams/ccm density. It is clear that beyond the ditch line, the packed snow will be less dense than the rest of the work pad. Equipment traffic will be infrequent, since its primary purpose will be to separate the vegetation and organic tundra from the spoil pile.

The process proposed for Arctic Gas snow road construction is a vast improvement over previous efforts, and is intended to produce a stronger, more stable surface. As the first step in preparation of the snow road, frost penetration will be accelerated, where required, by using low ground-pressure (LGP) vehicles traveling the ROW during the fall freeze-up period. If sufficient snow is available (either by harvesting or manufacturing), the snow will be leveled and compacted by rubber-tired motor graders (LGP's); then, in order to increase the density and surface hardness, pulvimixers (which can be towed by tractors) that will mechanically process the snow after the minimum of compacted snow cover exceeds 6 inches will be employed. Processing will be followed by roller compaction (rollers can be pulled by dozers or Delta Commanders). Once the required surface density and hardness have been reached, wheeled vehicular traffic will commence. If sufficient snow is not available or where the processing and compaction sequence does not produce a sufficiently hard surface, the processed snow road will be strengthened by the addition of water to form an ice-cap. An ice-capped snow road will normally have approximately 5 inches of water penetration in the snow surface.

Snow roads will be maintained by adding snow, water or sawdust, or a combination thereof, to rutted or broken areas of the surface. 1/ The roads will eventually melt and run off

1/ There is simply no evidence supporting the assertion of Green that 26 workers will be required to maintain the snow roads. Dau testified that, based on its Inuvik test, a snow road/pad construction and maintenance crew of 55 people for a period of 135 days per season per spread, in addition to a maintenance crew of 6 people for an additional 60 days, was appropriate (223/40,538).

naturally, and thus clean up and restoration requirements will be minimal. All stream crossings will be cleaned out before break-up.

2. Fistory of Snow Roads

Discussing the history of snow roads on the North Slope scores points for both promoters and detractors of the Arctic Gas plan. On the one hand, much of the criticism leveled against the Arctic Gas scheme is based on the failures of previous attempts to build roads constructed from ice and snow. These roads are variously called ice roads or winter trails, and admittedly have little relation to the Arctic Gas-type road. They were generally unprepared trails following relatively level contours across frozen tundra. Thus, criticism of these roads really has little revelance to the snow roads under consideration in this case. 1/ On the other hand, the fact that criticism is leveled at winter trails accentuates the fact that no Arctic Gas-type roads of any significant size have been previously tried in the North. The lack of experience with these roads is a key criticism against them.

EP-236 (Green Construction) presents the Alyeska experience with snow work pads. In 1975, Alyeska constructed two snow work pads and plans a third over a short distance. One pad is partially completed and being used to construct a 148-mile small-diameter gas pipeline. The pad is being constructed by spreading onsite snow drifts and leveling and compacting with dozers. Construction began in November 1975. Green states that as of March 1976, 60 miles of the pad were completed and most of the remainder will not be completed this season, as originally planned. However, John E. Latz, appearing at the request of Conservation Intervenors, testified after some contradictory statements that the snow pad itself was completed in

1/ Arctic Gas witness Philip Dau testified that existing and new winter trails will be used in surveying and drilling programs and in preparation of remote sites used for communications towers and equipment. Traffic to such sites will be minimal. Since a satellite system is planned for communication, use of winter trails will be greatly diminished.

Also, the only permanent roads will be those between the airstrips and their respective maintenance stations or material stockpile sites.

four weeks, but the small-diameter pipeline was not proceeding apace (193/32,593). 1/ The second pad is one-half mile long and was the only Arctic Gas-type pad built. Using snow machines, the pad took three weeks to build. However, it appears that Alyeska harvested snow from a lake 32 miles away (97/14,928-932). The third pad is being considered for constructing a large-diameter pipeline. The terrain is level, and an all-weather access road parallels the pad. The first attempt to construct this pad by collecting drifting snow allegedly failed when high winds dispersed the snow.

Arctic Gas has performed three snow road tests, and the last of these demonstrates the feasibility of the procedure. A very limited test was performed at San Sault, but the road was not successful as a result of improper equipment. The second test, at Norman Wells, was constructed late in the year. Here again, the available equipment only served to compress the snow already on the ground and essentially make an ice road. As a result of the information from these tests, it was decided that a more advanced test should be conducted. This test took place near Inuvik, Northwest Territories, in the winter of 1973-1974. Three different sections of snow road were built at Inuvik. The first was 950' and had a drop of 55', for a maximum grade of 17%. The second was 1700' over fairly flat terrain, with five creek crossings. The third was 1110', and was constructed to better understand the hillside or sideslope road construction. This section had a maximum cross slope of 11%. The great majority of snow used was harvested off a lake, since snowfall was particularly light that year. Some snow was manufactured. The density of the harvested snow was increased from 0.2 grams/ccm to 0.5 grams/cc. Trafficability tests were run with trucks carrying 22 tons and 25 tons. With the 25-ton load, about 200 uphill passes were made without tire chains, and no road deterioration resulted. Some 200 more passes were made uphill with a chain-equipped truck. It was found that only the top 1" or 2" of road surface deteriorated. During December and January, about 1600 trafficability vehicle passes were made over the main road and 1400 passes over the sideslop section.

1/ Mr. Latz's disingenuous testimony concerning the construction of the Alyeska snow pad is typical of this witness's entire presentation. In this instance, the witness gave the initial impression that Alyeska experienced considerable difficulty and delay in constructing its snow pad (193/32,565, 32,570-572). However, on more specific examination by the Presiding Judge, he conceded that Alyeska had built the snow pad in less than four weeks and that there was an abundance of snow (193/32,593-596).

Some potholes developed, particularly at or near curves in the road. Some repairs were made with a sawdust, snow and water mixture. At subzero temperatures, it was found that traffic could resume within a half hour after the mixture had been applied.

In early December, before the snow-harvesting operation, tests were conducted in snow manufacturing using a standard ski hill gun. All that was required for this operation was a source of water (which in this case was a tank truck), air compressors, and a snow gun along with the necessary hoses. Air and water were fed by separate lines to the nozzle, and a fine spray was produced which turned to snow. Efficiency increased at lower temperatures, but snow could be produced at ambient temperatures as high as 36°F. The equipment used at Inuvik was much smaller than that now available.

The trafficability studies were shut down on January 22 and resumed on April 6 to study the spring break-up deterioration. The shutdown was ordered because all the runs that had been made at that time simply were not damaging the road. The runs made on April 6 still did not do any damage, and thus the runs were stopped until April 27. On May 5, at a temperature of 25°F, some deterioration began to show, but 96 truckload passes were made on that date. On May 6, with temperatures around 35°, 68 truck passes were made. However, rutting and deterioration accelerated, and tests were concluded. Nevertheless, roads could still be used by soft-tracked vehicles hauling sleighs. There has been continuing investigation of the Inuvik site, but the 1973-1974 test provides the basic support for the Arctic Gas plan. 1/

3. Snow-Accumulation Process

There are basically three methods by which snow can be accumulated for the construction of snow roads (in probable ascending order of cost): (1) snow fences; (2) snow manufacture; (3) snow harvesting and hauling.

a. Snow Fencing

Snow fences are barriers which serve to collect drifted snow. Fences will be erected in September on 470 miles

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1/ Arctic Gas-type snow roads have been researched in Greenland, Antartica and other places, but not on the scale of the Arctic Gas plan.

of the route. Snow fences will not be erected in the boreal forest, where trees prevent snow blowing. Placement will be accomplished by Rolligons or some other LGP vehicle, with helicopter support. The vehicles will be equipped with small drills capable of drilling holes for snow fence supports. Since snow fences will be erected before there is any indication whether snowfall or water availability are adequate for gathering and snow manufacturing, the cost of snow fence erection will be incurred regardless of the eventual need for the snow collected at the fences. Arctic Gas intends to build fences 4' high. They will be installed down the center of the ROW and parallel to it. Gaps will be maintained between the fences to allow caribou to move through. Arctic Gas witness Dau considered the installation of snow fences a relatively simple operation. He was told by Alyeska that it was installing posts at 10 foot centers at a pace of one post/minute. At this rate, one could easily do 1 mile/day (99/15,304).

There has been at least one detailed study on snow fences. The CRREL Report 1/, although analyzing fences in a year of apparently unusually heavy snowfall, 2/ stated: "The first evaluation of induced snow accumulation was a visual inspection on November 8, 1972, two months after snow fence installation. . . . the 1.5 m fence section had drifted almost full, with only posts and up to 10cm of the fencing material exposed" (163/26,789). The Report recommended that post spacing be three times fence height and found that fences of approximately 50% density are most effective for multiple fences.

Snow fencing was also erected on a section of the Alyeska ROW near Toolik. Although the fence was not installed until late December 1975, sufficient snow had accumulated to allow removal of the fence by the following month. Indications were

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1/ Corps of Engineers - Cold Regions Research and Engineering Laboratory - "Accumulating Snow to Augment the Fresh Water Supply at Barrow, Alaska" (January 1975).

2/ However, Dr. Carl Benson of the University of Alaska has started to study snowfall patterns because he questioned the accuracy of the snow-measuring equipment used in the Barrow Studies. Benson has developed his own gauge for North Slope conditions, and his preliminary findings, according to Arctic Gas witness Williams, are that long-term snowfall records may be low by a factor of 3 (163/26,812A-816). However, Benson has neither been called as a witness nor sponsored an exhibit in this case.

that if the fences had been installed in September, there would have been sufficient drifted snow by October (163/26,789; 26,912-913). Dau also testified that there has been many published reports on snow fencing, and the techniques have been used in Colorado and Canada (23/3478-80).

There is no reasonable question that snow fencing is a proven, reliable method of accumulating natural snowfall. The effectiveness of snow fences, of course, depends on natural snowfall. While the amount of snowfall in this area is not great, varying according to year, month and location, the strong winds on the North Slope will cause the snow that does fall to blow and form drifts at the fences. Although there has never been a year when there was no snow at all on the North Slope, Arctic Gas intends to use snow fences for just part of its total snow needs and to manufacture snow for the rest. As shown below, it is clear that this is a reasonable plan.

Alaska witness John Becker presented a statistical analysis of snowfall data from the Barter Island weather station. These weather conditions are representative of those encountered on the Arctic Gas route (163/26,787). Unfortunately, weather data spanning a number of years from different sites on the Arctic Coastal Plain are not available. The United States government has been keeping records at Barter Island (near Kaktovik) for 27 years. The records show monthly average cumulative snowfall through September--4.2", October--9.6", November--5.7", and December--3.8". The table shows mean monthly snowcover in October--8", November--12", and December--13".

Becker calculated the standard deviations for monthly snowfall and found them to be very large when compared to the monthly averages (e.g., October --8.1"). Thus, there is a "high" probability that snowfall in a given year will vary considerably from the average snowfall. He also calculated the 25th percentile of cumulative snowfall. This represents approximately the snowfall which would be exceeded three winters out of four, or conversely, snowfall which would not be reached one winter out of four. These are September --1.5", October --7", November --1", and December --14".

Becker's conclusion was that to construct snow roads in the early part of the winter season, natural snowfall would have to be enhanced, e.g., by snow fences. As noted above, Arctic Gas is aware that snow fences would be needed to accumulate significant amounts of natural snowfall. Becker did not state when or if snow manufacturing would be necessary.

Williams, commenting on the Becker analysis, discounted the September snowfall because he thought that melting would occur in September. He concluded that the 8.9" October average would, in conjunction with snow fencing, be adequate for work pad and snow road construction. He testified, however, that 9 out of 27 years studied had less than 4" in October, which may be marginal for using snow fences. Some snow would probably have to be manufactured or hauled in these years. This is why Arctic Gas has not relied solely on nature's bounty for its snow road commitments.

b. Snow Manufacture

The snow-making process is similar to that used on most Americana ski slopes. Snow is "created" by dispersing minute water particles and air under pressure into freezing or near-freezing ambient air. The density of the produced snow can be controlled, and lower temperatures aid the efficiency of the operation. Snow manufacture is a feasible, reliable method of amassing sufficient snow for the construction of snow roads.

Arctic Gas plans to commence snow-manufacturing in early October, if sufficient snow has not yet accumulated at snow fences to start building snow roads. Witness Williams emphasized that snow manufacturing would only be required in the early part of low-snowfall seasons. Recent tests at Edmonton demonstrated that three units of snow manufacturing equipment would produce enough snow for ½ mile of snow road/pad a day. These units have a through-put of 300 gallons/minute, and 6 of them would be placed at each spread. However, new snow-making machines, each with a through-put of 1,000 gallons/minute, are now being considered by Arctic Gas. Each spread would have two of these larger machines. These units are presently in the "conception" stage and have yet to be built and tested.

Snow can either be produced at the water source and transported to the ROW, or the water can be hauled to the ROW and converted to snow there. Williams stated that a combination of these methods would probably be most economical, because it would best utilize equipment which would be available at the work site.

The snow-making machines are very light and can be mounted on soft-tracked vehicles. The equipment proposed to supply water to the machines from the sources consists of twenty 6,000-7,000 gallon tanks mounted on large industrial sleds and/or 30-ton all-terrain Delta Commander units. In all likelihood, 10 Delta Commanders will be available at each spread. Each Delta Commander will carry a tank, and each Commander will also tow a sled carrying a tank. Insulation and heating cables will be used to prevent water in the tanks from freezing. These tanks will then move along with the snow-manufacturing units, continuously supplying water along the snow road. The

Delta Commanders have been in use for several years in the Arctic. They are LGP vehicles, even when pulling sleds. To protect the tundra in supporting Delta Commanders and sleds fully loaded with water, there must be about 8" of frost penetration and 8"-9" of compacted snow (163/26,799-810). Given the projected length of the haul, the ten Delta Commanders with 20 tanks should be able to keep the two snow-making units operating almost continuously. As the work progresses and a road suitable to support conventional track equipment is prepared, these "trucks" would also be used to haul water.

c. Harvesting and Hauling

Snow will be harvested and hauled from nearby lakes beginning in October, if this is needed to supplement snow fence and snow-manufacturing output. Snow harvested from lakes is a much denser snow because it has been "worked" in harvesting. It is also relatively easy to gather since it lies on a flat area with no vegetation. Also, witness Dau stated that there are locations on the ROW where it would be desirable to fill in deep depressions. This could be most effectively achieved through collecting and hauling snow (23/3481-82).

4. Timing

Timing is a critical element in the Arctic Gas plan and is the most hotly-disputed component of the snow road issue.

Efficient and timely snow road construction is essential in the Arctic Gas pipeline construction scheme. As stated earlier, Arctic Gas plans to erect snow fences in September, with snow manufacturing beginning in early October, if sufficient snow has not yet accumulated at snow fences. Snow may also begin to be harvested and hauled from lakes at this time. Snow road construction would begin in mid-October and be completed by the end of December.

Following the above schedule should allow pipeline construction to begin in late October or early November. Pipeline construction would begin after 5-10 miles of snow road is completed. As pipeline construction proceeds, snow road construction will continue using snow accumulated at snow fences, augmented, if necessary, with manufactured or hauled snow. It was estimated by witness Williams that at least 20 miles of pipeline construction would be completed at each spread before Christmas. 1/ Dau testified that Arctic Gas has assumed that

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1/ The importance of this is because of its impact on pipeline construction schedule. Williams' schedule has pipeline construction extending from November 1-May 1.

snow roads will likely deteriorate sufficiently to be unable to carry heavy loads by April 15. However, in his opinion, this date could be extended by a month (23/3495). (See Inuvik test, supra) Williams, in fact, scheduled pipeline construction until May 1.

The most significant factor to consider in a timing analysis is the beginning date of snow road construction. Arctic Gas concedes that to achieve its pipeline construction schedule, an early winter construction start is needed. (See construction section, supra.) Historically, the months of November and December have had less severe temperatures than January or February. Thus, it is important to take advantage of better weather which occurs early. To achieve early pipeline construction, snow road construction must begin as early as possible. Early snow road construction is contingent on early vehicular access to the state and federal lands. It is concluded, as shown below, that the opening date is dependent almost exclusively on frost penetration, because the construction method will permit snow-making machinery to build its own road ahead of it for further tundra travel even if there is inadequate natural snow cover so as to require snow-manufacturing.

The State Division of Lands regulates tundra travel on state lands, and the U.S. Fish and Wildlife Service regulates it on the Wildlife Range. These government bodies issue permits for tundra traffic. 1/ Generally, two conditions must be met before vehicular traffic is allowed: snow cover and frozen ground.

All cross-tundra movement is prohibited on the tundra at the time of the annual thaw. This "closure" order is usually issued in late May. Most vehicles are not permitted to cross the tundra until the ground is refrozen and covered with snow. At this time permits are issued for cross-tundra traffic. The initial dates for these permits have ranged from October 20 - November 18 (EP-238, Table 15). Certain LGP vehicles like Rolligons, however, are permitted on the tundra during the summer and fall once the ground has thawed to a sufficient degree to absorb the impact of these vehicles.

1/ Alaska witness William Copeland testified that in issuing permits, the Department will allow destruction of a portion of the tundra if it is shown that this is necessary for a worthwhile project. For example, Alyeska was permitted to build a gravel road.

The time when LGPs are able to cross the tundra is significant. As already stated, Arctic Gas intends to begin erecting snow fences in September. This would be accomplished, at least in part, by LGP vehicles. Alaska witness William Copeland testified that Rolligons, as opposed to other LGP vehicles, would be permitted to place snow fences in September and October, even if there was no cover or substantial frost penetration (97/14,868-870).

The snow-manufacturing process presents slightly different considerations. First, snow manufacturing requires a temperature lower than 36°F. This presents no problem, since the mean monthly temperatures at Barter Island from 1948-1973 were: September +31.4°F., October +15.9°F., November +0.8°F., December -12.0°F. More importantly, to protect the tundra in supporting loaded Delta Commanders and sleds, 8" of frost penetration is required, in addition to 8"-9" of compacted snow. In the usual situation, the critical factor has generally been snow cover, because the terrain is generally frozen by the time adequate natural snow is available. Arctic Gas, however, plans to manufacture snow at those times when snowfall is light. Thus, frost penetration is the only relevant consideration dictating tundra access in the present case.

El Paso, on brief, concedes that the only significant date is the frost penetration date. El Paso, however, continues to maintain that the traditional opening dates be used in assessing Arctic Gas' snow road construction schedule (EP Reply Env. Brief, 27). This is clearly wrong, since those opening dates were predicated on adequate snow cover, which is not the relevant consideration here.

The only reasonable method to analyze Arctic Gas' "opening date" is on the basis of climatological data on freezing degree days. El Paso terms this its "alternative method" and alleges it is filled with uncertainties. Dau testified, however, that after only 200-300 freezing degree days, Rolligons would begin compacting snow that has accumulated at snow fences (accelerating frost penetration), and snow manufacturing could commence. 1/ Based on an analysis of data from 1970-1974 at Inuvik, the average date at which 300 degree days was reached was October 16. 2/ Other factors do affect the accessibility

1/ A freezing degree day = average of the maximum and minimum temperatures referred to 32°F. Thus, if the average temperature is 20°F, this equals 12 freezing degree days.

2/ El Paso counsel Raymond Bergan suggested that data from Inuvik from 1957 shows the average date of which 300 degree days was reached was October 22 (233/ 40,578).

of the tundra, including vegetative cover and water content of the soil, and the final determination as to the specific date will be site-specific. 1/

In fully understanding the "opening day" concept, further discussion of exactly how Arctic Gas will use its snow-making machinery is helpful. The Arctic Gas snow manufacturing plan involves either having some snow-making equipment at water sources prior to winter or moving the Delta Commanders to the water sources over even minimal snowcover. This plan depends on two factors: minimal snowcover for the Delta Commanders going out to the sources, and sufficient frost penetration to withstand the loaded Commanders.

Expanding on the methodology of construction, not only the Delta Commanders, but most, if not all of the snow road construction equipment can be pulled by soft-track vehicles (163/26,810-812).2/ Therefore, while adequate snow cover and frost penetration (8") would also be needed before these vehicles could cross the tundra, again, snow manufacturing can provide the necessary snow cover. Dau explained that Arctic Gas planned to move snow-making equipment in with the first equipment that goes to Alaska on barges and that it would first be used on the stockpile sites at the coast. Then the equipment would be moved to a borrow source. These sources are generally located near water sources. Thus, Arctic Gas would begin to make snow roads from the borrow sites to the ROW and then down the ROW before any snow was on the ground, providing the temperature would allow for snow manufacturing and there was adequate frost penetration (23/3483-84).

1/ Williams also testified that snow road construction can commence with zero frost penetration, if there is some snow cover. Rolligons could be used to compact the snow, which would induce frost penetration. This seems to conflict with Copeland's testimony, which stated that frost penetration was necessary for Rolligon use in September and October (163/ 26,817-834).

Williams also testified that a fair thickness of well-compacted snow might lessen, to some degree, the necessary amount of frost penetration (163/ 26,904-905).

2/ This is only critical in the first year anyway, since the heavier equipment would "summer over" at water sources in preparation for the next winter construction schedule.

Williams described the construction of the access road from the Camden Bay stockpile site to the ROW. He stated that the initial snow road required to move the materials can be fairly minimal with the use of Delta Commanders and sleds. The road could be 30' wide and 12" deep of 0.5 grams/ccm snow, with 8" of frost penetration. Some heavy equipment could be transported on the road if broken into components and placed on sleds. Assuming insufficient snowfall, water from Camden Bay sources would be used to manufacture snow. As already noted, there would be some equipment located at water sources near the ROW in the winter prior to the construction season. Thus, snow road construction would proceed in both directions. When pipe is hauled from Camden Bay by conventional vehicle, a high-speed haul road would be needed. This better road, however, would not be needed immediately, because 18 miles of pipe will have been hauled into the camp the previous winter.

Similarly, Williams testified that in the early winter season, when the distances from the camps and stockpile sites to the pipeline construction work location is short and when snow might not be available, it is not necessary to have a high-speed traffic lane adjacent to the work pad. All that is required is compacted snow to protect the surface vegetative cover. When the haul distances are short, pipe can be hauled with tractor-drawn sleighs, and workers can be transported by LGP vehicles. As the distance increases, the availability of snow will improve, and snow roads will be completed (163/26,787).

Once the "opening date" aspect of the snow road construction plan is accepted, there is no credible evidence that Arctic Gas will be unable to construct adequate snow roads in a timely fashion. Arctic Gas has estimated that it can construct one-half mile of snow road/pad per day, by using snow manufacturing. Other means of accumulating snow would be faster. (See Staff Geot. Brief, 8). Green Construction, in its criticism of the Arctic Gas plan, assumed a one-half mile/day rate regardless of the source of the snow and estimated that 30 miles of snow road would have to be completed before pipeline construction could commence. In fact, only 5-10 miles of snow road are necessary before construction could commence, and this is possible even using Green's unrealistic assumption that all snow would have to be manufactured. Finally, Green overestimated the overall length of snow road that will be necessary for the entire project, <u>supra</u>.

It should be noted that the Arctic Coastal Plain construction is scheduled for the third construction winter. During the first two winter seasons, Arctic Gas will gain snow road construction experience in Canada. Dau testified that if experience indicated that the expected mainline construction progress could not be obtained along the Arctic Coast, there would be sufficient time to mobilize an additional spread in Alaska in the third winter season. This would reduce the required average single-spread production per season from 65 miles to 49 miles. Similarly, Spread "G," currently not proposed to be utilized in the third winter season, would be available in the Canadian section of the Arctic Coastal route, reducing average spread production per season there from 67 miles to 47 miles. The estimated capital costs of these two additional spreads would be $118,600,000 (233/40,549). Thus, the amount of snowfall or speed of construction can only affect cost, and not the timeliness or environmental safety of the project.

Green stated that terrain grades would be a problem for snow road construction. First, Green states that when the roadway grades exceed 10%, it will be necessary to re-route the road outside the ROW to attain more favorable grades. This will require additional construction time. Second, it was noted that where grades are steeper than 15% for lengths of alignment in excess of 200', and where cross slopes are greater than 5%, a more sophisticated snow work pad than is planned by Arctic Gas must be considered. Third, small variations in ROW slopes can have very large effects on snow requirements. By way of illustration, a transverse slope as minor as 2% could double the snow embankment quantity.

The Green Construction witnesses were uncertain about the extent of the grade problem on the North Slope. Green witness William Powell testified that he thought there were some "pretty fair grades" in Alaska, at the river crossings. Other than this, he conceded that the slope is fairly flat, becoming more rolling as one goes east. However, Powell seemed unsure whether there are any grades over 10% in Alaska, although he was certain there are grades over 15% in Canada (166/27,201-210).

The FEIS of the DOI, "Alaska," (ST-26) states that information submitted by Arctic Gas indicates that 90% of the slopes traversed by the route in Alaska are less than 3° (5%). There are 56 places where the slopes range from 3°-9°(5%-15%), and most of the steeper slopes are near stream crossings and locally may approach 20° (35%).

Similarly, the FEIS of the DOI, "Canada," (ST-27) states that most of the route in Canada is flat, although some areas contain slopes of 5%-10%. Larger slopes occur in scattered areas, generally at stream crossings.

Arctic Gas is apparently aware of the added snow requirements of graded terrain, but it is not clear that it has taken this into account in its construction plan. At Inuvik, tests were run over terrain with grades up to 17% and cross-slopes up to 11%. Dau testified that the depth of the snow road at Inuvik was 2½', because of sloping creek crossings and hummocks (25,3,751-54). Williams testified that, although the terrain is generally flat on the North Slope, stream crossings have banks up to 10' high. At these crossings, some grading will be required to ease the slope and facilitate pipeline construction. Snow fill can be used. However, Williams also testified that a level terrain was assumed for the Arctic Gas water requirement study; this was not a significant omission because of the very liberal requirement estimates. One indication that Arctic Gas has considered snow fill needs is Dau's testimony that the average thickness of the traffic lane will be 18", but 12" is adequate on level terrain (23/3465-70) In sum, the consensus is that additional snow will be needed for grading purposes. Arctic Gas should include such estimates in its plan, if it has not already done so.

Green also criticized Arctic Gas for not fully considering ice bridge problems. It was noted that numerous ice bridges will be needed to cross the North Slope and the Mackenzie Delta. These bridges will be required at those streams whose warm spring tributaries allow year round flow or where the tundra has frozen to carry equipment. Crossing the rivers can be difficult and hazardous.

Dau testified that it is a common and accepted practice in the north to use ice bridges to cross streams which have a year round flow. These bridges are constructed by removing the insulating snow cover and pumping water onto the road surface to thicken the ice (20/3051-55). Dau stated that ice bridges will be used on the major rivers of Northern Canada that do not freeze to the bottom. Green's main concern here seems to be the lack of specific planning for ice bridges and the timing difficulties they could present. Again it is basically a question of timing, and cost and the need for proper planning. Arctic Gas has developed adequate plans for the construction of ice bridges.

5. Costs

Arctic Gas has estimated that it will cost $50,000/mile to manufacture snow for snow roads. However, Arctic Gas has not submitted a general cost figure for snow road construction but has included snow road costs in its pipeline installation costs. Dau offered a "ball park figure" of $40,000-$50,000/mile for constructing a snow road/pad in which manufacturing, hauling and snow fences are used (23/3501-02). Williams testified that Arctic Gas has assumed the cost of snow fences, hauling and manufacturing unrealistically lengthy segments of snow road.

As elsewhere, El Paso criticized these costs. Green Construction, in EP-236, estimated snow road costs using the three gathering techniques, for the Alaskan and Canadian segments. Green concluded that Arctic Gas has greatly underestimated the cost of snow road construction primarily by not taking into account snow necessary for grading and leveling the work pad. As stated earlier, however, several of the other assumptions made by Green vary with Arctic Gas' assumptions: length of snow road/pad; length of additional snow road; amount of snow fencing; rate of production; 30-mile snow road lead time to begin pipeline construction; necessary equipment; crew and wage rate, etc. Moreover, Green's method of analysis was to determine the cost of using each snow accumulation technique on the entire route, which could grossly inflate the cost figures. Dau considered Green's costs for harvesting snow "ridiculous" and without apparent relationship to the route of the pipeline.

Finally, Green witness David Argetsinger curiously diluted the impact of the EP-236 cost estimates by stating on redirect that the costs estimated here were not carried into the El Paso cost analysis. Argetsinger testified:

> When we got to the cost analysis, it was--we were using Arctic's estimate. The information we had as our basis. And when we compared our figures with theirs, it appeared that probably the dollars we had in here may have been close to the dollars they had but because their estimate was made up slightly differently, it was impossible to make a complete

> comparison, but we could conclude that probably we would not be able to--if we took a fairly conservative approach to the snow-making procedures, there would be no significant increase in cost from using our estimate (167/27,443-444).

In final analysis, those potential construction problems relied upon by Green as possibly hindering the Arctic Gas snow road plan do not invalidate the plan. It is found that from a geotechnical and construction point of view, the Arctic Gas proposal to use winter snow road construction is feasible.

E. Arctic Gas-- Cross-Delta Construction

Canadian Arctic Gas originally proposed a circum-delta route, in which the pipeline skirted the western edge of the Mackenzie Delta, joined a lateral extending from Richards Island at Travaillant Lake Junction, and continued to Thunder River and south.

On February 12, 1976, a cross-delta amendment was proposed. This route leaves the former prime route near Shingle Point (MP 291) and proceeds across the delta to meet the Richards Island supply line at Tununuk Junction (MP 372). The route then proceeds south and joins the former prime route near Thunder River. In addition, Canadian Arctic Gas proposed a 24" supply lateral to the Shell Oil Niglintgak plant and a relocation of the 30" lateral to the Gulf Oil Parsons Lake Plant. (See map, AA-34,§8b1.3 Figure 2)

The total length of the original prime route is 415.9 miles. In addition, there are 2 miles of twinned pipeline under the Point Separation and Peel crossings. The total length of the cross-elta route is 277.3 miles. In addition, there are 36.5 miles of twinned 36" pipeline through the delta. 1/

Three issues have been most widely discussed on the record concerning the cross-delta route: operations and maintenance, snow geese and beluga whales. Given adequate compliance with conditions, none of these potential problems are significant or justify denying certification of the route. Each issue will be discussed in turn, and then several other relevant considerations will be addressed.

1. Operations and Maintenance

The main operations and maintenance concern is the inaccessibility of the pipeline for repairs during certain periods of the year. Of course, for this problem to eventuate, the pipeline must first suffer an outage, and this outage must occur during specified seasons. The chance of all factors occurring at once is remote.

a. Risk of Outage

As stated *supra*, twin pipelines are planned for 36.5 miles of the route through the Mackenzie Delta. While these twin lines will be about 50' apart on land, they will be about 200' apart under Shallow Bay. Gas will be flowing through both lines concurrently.

1/ The cross-delta route, including the twinned lines, is $190 million less expensive than the original prime route (AA-36 page 3).

Arctic Gas stated that it has proposed twin lines because of the possibility of inaccessibility and not as a reaction to any increased risk of outage. In fact, it has concluded that the risk of outage within the delta is very low, on the order of once in several hundred years (101/15,521). The probability of failure occurring in both lines is extremely remote. Although this general risk assessment was based only on AGA and Canadian studies of "conventional" pipelines, Arctic Gas witness Lee Hurd testified that the unique geotechnical conditions occurring in the north do not suggest that failure would be more probable there. In fact, Hurd observed that because there would be no "outside forces" on the North Slope that could cause damage, the frequency of failure would be somewhat lower than that of the typical North American pipeline.

Arctic Gas studied the geotechnical aspects of the cross-delta route to a greater extent than the original prime route. The witnesses testified, without substantial dispute, that the delta pipeline would be designed so as to greatly minimize any potential danger to the integrity of the line.

The cross-delta route will cross 4 or 5 rivers with ice scour potential attending breakup. 1/ However, the 4.5-mile crossing of Shallow Bay does not experience this problem. In fact, the cross-delta route avoids the Point Separation crossing of the circum-delta route, which presented the most severe ice jam and scour problems. While ice scour potential does exist to some extent on the amended route, it tends not to occur in the outer delta where ice break-up usually occurs by rotting in place rather than by large chunks of ice breaking off and rapidly moving (101/15,526). The pipeline will be designed to withstand the foreseeable ice scour problems that do exist.

The pipeline will be buried in highly frost-susceptible soil, in that it will be laid in unfrozen ground under bodies of water. However, extensive testing has revealed that although the silt is highly frost-susceptible, it has a low shut-off pressure (pressure at which water is neither taken into nor expelled from a soil during freezing). Thus, as the frost bulb penetrates, ice lenses will not develop, and the potential for frost heave is lowered (102/15,596). Burial depths of 10'-20' will generally be sufficient to maintain the frost heave within safe limits.

While there will be a slight enlarging of the active layer during the inactive season, this will not reach the depth of the pipeline, and thaw settlement is not a problem (102/15,595).

1/ The scour is the cutting of river or ocean bottoms by compacted ice.

Also, while there is theoretically some potential for liquefaction in the Shallow Bay area, Arctic Gas witness John Clark testified that he has run 29 tests and has not yet been able to liquefy the soil within set conservative criteria (102/15,555-558).

b. Ability to Repair

The chief concern is that, in the unlikely event of a pipeline outage, the affected area will be inaccessible to repair crews. There are several periods during the year when repairs would be difficult or impossible: 4-6 week break-up period in early spring, when flooding and ice are likely to prevent access; 2-3 week freeze-up period in late fall, when soft ice would make access difficult; several 1- or 2-day summer surge periods when severe flooding would prevent access. During the flood stages, 35-40 miles of the delta may be inaccessible, while icing would prevent access only to the channels crossed by the route.

A small pipelaying barge will be stationed in the delta area on the remote chance that it would be required for maintenance of sections buried under channels. Maintenance crews will have special amphibious transport capability and balloon-tired LGP vehicles to ensure access in summer. Depending on when repairs are necessary, summer repairs might impact snow geese. Dr. McCart testified that any disturbance, however, would be short-term.

2. Environment

a. Snow Geese

The primary environmental concern of the cross-delta route involves snow geese. These migratory waterfowl are white with blackish primaries. They breed in Arctic America and migrate south. They stage in varying numbers on the outer Mackenzie Delta from late August to late September. During a normal year, when the Alaskan North Slope is relatively snow-free, a relatively small number of snow geese--25,000--stage on the delta. However, if there is an early, heavy snowfall on the North Slope, as occurred in 1975 and which reoccurs about once every 8 years, 275,000 geese may arrive at the area around Shallow Bay. Arctic Gas proposes summer construction across Shallow Bay.

The three main hazards to snow geese stem from compression station noise, human ground activity, and aircraft overflights. The compression station problem has been largely alleviated by Arctic Gas' intention to move CD-08 from the central part of the outer delta eastward to Tununuk Junction (Gunn direct testimony, 172/28,229; statement of Counsel Daniel Collins, 133/21,370). Arctic Gas' ornithology witness Dr. William Gunn considered this his most important recommendation concerning the cross-delta route.

Similarly, the impact from human ground activity will be substantially mitigated by restricting human activity to the construction and camp sites. In any event, because of the nature of summer activity, workers will have no means of moving a significant distance from gravel work pads. Vehicular traffic on land will be restricted, and water vehicle traffic will be controlled. Weapons will be few and strictly controlled and hunting prohibited. Sound emissions will be reduced by silencing devices (Ex. AA-34). Presumably, conditions so requiring will be imposed by Canadian authorities.

Aircraft overflights present the most potentially significant disturbance to snow geese. It is clear that snow geese use their fall staging on the Mackenzie Delta to increase their body weights and fat reserves in preparation for their long southward migration. It is likewise apparent that snow geese are extremely sensitive to aircraft overflights, flushing in response to over-flights of up to 10,000'. With the present airplane frequency of one flight every 4 hours on the North Slope, snow geese feeding time is potentially reduced 2% - 3%. If flights are increased to one flight very 2 hours, feeding time is potentially reduced 8% - 10%. If this loss of feeding time is added to the "fuel" expense in flying away, young birds might lose up to 20% of their "fuel capacity." The result is that birds would alter their migration patterns to stop more frequently to feed. This may bring them into areas of more intense hunting or less plentiful food supplies (18/2705-68). Of course it could just as well bring the geese into areas of less hunting pressure. Thus, disturbance on the delta may result only in a short-term change in migration patterns, or in the worst case, greater mortality to the flock after the single summer construction season. Even if a reduction of the flock does result, however, there is evidence that waterfowl management techniques can be successfully employed to reestablish the preexisting size of the flock. Alcan witness David Hickok, a uniquely qualified specialist in arctic environmental issues, testified that bird populations can be enlarged by manipulation of the land: "I have managed wildlife refuges in places in the country where we had two or three hundred geese, and with some manipulation of the habitat end up with 30,000, 50,000" (206/35,320). In responding to a question concerning the alleged threat to staging on the delta, he added:

> I have worked with snow geese in the St. Lawrence country and also right over here in Delaware; the largest population of snow geese on the Atlantic Coast come to a place called Bombay Hook refuge which is just down below Marcus Hook refinery about ten miles and snow geese, like any other goose, they are going to get their requirements and if they don't get them one place they will get them another (206/35,321).

Brina Kessel, another Alcan witness and an ornithologist, expresses a contra view, asserting that waterfowl management was in its infancy in the far north and that flock enhancement traditionally has been through reestablishment of breeding habitat. She described impacts as more pronounced in the Arctic, and therefore more difficult to mitigate because of the more intolerant climate. 1/

Dr. Gunn testified that disturbance to geese can be held to an acceptable level if aircraft flights are kept below a rate of one every 2 hours. The existing rate in the delta is one every 4 hours During construction of the cross-Delta pipeline, it is estimated that there will be 4-5 flights per week. During operations, there will be 3-4 flights per month. Thus, the projected number of flights will not approach Gunn's estimated danger point. In addition, Arctic Gas witness Russell Hemstock testified that aircraft traffic will avoid any area of snow geese staging and be curtailed during this period. Flights will also maintain a 2,000' minimum altitude. In sum, Dr. Gunn testified that if aircraft flights are limited as projected and ground activities are restricted, construction can continue in a normal staging year with no critical effect on snow geese. If there is any disturbance to snow geese, they would have the alternative of staging on the North Slope in the usual year.

The most significant hazard pertains only to the period of unusually heavy Delta use. It is only in the 1 year in 8 when heavy snows on the North Slope lead to increased staging on the delta that disturbed geese would have no North Slope alternative. And, it is unclear whether impacts on these geese would be severe if overflight and ground activity restrictions are enforced. Dr. Gunn suggests that construction cease during these periods-- taking 1975 as the worst case would require construction to cease from September 7 - September 21. Arctic Gas refuses to commit itself to specific conditions at this time, stating on brief that it will evaluate the scope of construction activities that can be continued in such years "on a site specific basis, having consideration for concentration areas, construction activities, etc." (AG Env. Brief, 74).

While it may be premature to hold Alaskan Arctic to construction conditions placed on Canadian Arctic, several recommendations concerning timing of construction deserve serious consideration. Dr. Gunn has suggested that work pads on each side of Shallow Bay

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1/ As an indication of how scientists may view things differently, Dr. Kessel is willing to approve construction within one mile of an active peregrine falcon nest. All other ornithologists, whether on a general or site-specific basis, suggested much larger buffer zones. (See infra) The peregrine, unlike the North Slope waterfowl, is on the endangered list and is almost extinct.

scheduled for construction in the year preceding pipeline construction be built in August, not September. Second, Arctic Gas proposes Shallow Bay construction from June 15 - October 1. Mr. Hemstock suggested that Arctic Gas is presently considering starting construction earlier to avoid impact on snow geese (100/15,456).

Last., even if the flock is adversely affected during the year of construction, hunting snow geese on the North American continent could be curtailed. DOI witness Maxwell Britton conjectured that the snow goose is already covered under a migratory waterfowl treaty between Canada and the United States, which sets the harvest of snow geese by hunters based on bird population.

b. Beluga Whales

There has been some discussion on the record concerning the impact on beluga (white) whales in Shallow Bay. These whales average 10' in length, occur chiefly in the northern seas and migrate to the Mackenzie estuary each summer. Submerged adult whales cannot be seen in the turbid water of the estuary, while calves, because of their dark color, are difficult to sight at all. F.F. Slaney & Company, Ltd., as consultants for Imperial Oil Limited, studied beluga whales in the Mackenzie Delta estuary from 1972-1975 (AA-96A). Whales were present in the bay from late June to late July. Slaney suspected that the whales used the warmer waters of the Bay for calving. In several of the years studied, a number of belugas penetrated the Bay to a point south of the proposed pipeline. However, most of the animals remained seaward of the proposed route.

Slaney observed the effect of barge traffic, dredging and construction of artificial island activity on whales. The report concluded that there was no significant effects on whales' behavior or movement. Moreover, the 1975 total of harvested animals in the estuary was close to the mean of the last 4 years, suggesting a lack of adverse impact.

The Arctic Gas Environmental Report (AA-34) suggests that noise is probably the most dangerous impact, and whales will move a safe distance away when confronted with a new sound source. If whales are seaward of the source, they will have a less panicked reaction, and some animals even display a cautious curiosity once assured of ready escape. Hemstock testified that construction activity wouldn't disturb whales more than 1 mile away.

Finally, although there have been no specific studies on whale tolerance of turbidity, the existing high turbidity in the delta region suggests that any additional turbidity from pipeline construction would not have a serious impact.

In sum, there is no indication that construction activity will have a detrimental effect on whales in Shallow Bay. Any effect that is felt is likely to be minor and short-term.

c. Significant Advantages and Other Considerations

There are several significant advantages of the alternative routing from the construction and environmental point of view identified on the record. Some of these are self-evident: the route is $190 million less expensive, traverses 138 fewer miles and will require two less compression stations. Of course, the shorter length of the route means it will disturb less wildlife habitat and vegetation and require fewer miles of right-of-way. Arctic Gas has stated on the record that it would accept a certificate not crossing the delta.

More specifically, Arctic Gas witness R. D. Jakimchuk testified that the cross-delta route is marginally preferable to the original prime route from the standpoint of terrestrial mammals. While the cross-delta route might be more likely to confront grizzly bears and occasional small numbers of polar bears, it avoids Porcupine caribou migration and watering areas on the west side of the delta and potentially serious interferences with Dall sheep on the circum-delta route (Ex. AA-99). Similarly, Arctic Gas witness Donald Dabbs preferred the cross-delta route from the standpoint of vegetation. As stated supra, less vegetation, especially forest vegetation, will be disturbed. Moreover, the proposed route traverses less steeply sloped terrain, and thus erosion control is easier. Finally, revegetation efforts would be enhanced by the annual floodings which deposit nutrient rich river silts in the area (Ex. AA-97A).

The FEIS states that the cross-delta route can have potentially severe adverse effects on fish. However, Arctic Gas witness Dr. Peter McCart testified that construction and operation of the pipeline can be accomplished without a detrimental effect on fish populations. Shallow Bay itself is quite depopulate and has high sediment levels. The construction of an experimental trench in Shallow Bay in 1975 caused little apparent disturbance to fish (Ex. AA-103). Dr. McCart was not concerned about the impact on overwintering fish, since unlike northern Alaska, there is ample freedom in Canadian streams for fish to move to other areas if the pipeline crosses an overwintering area (15,466-467). Sediment levels should be monitored in streams, although the slower-moving streams encountered in the cross-delta route will likely make any sedimentation problems more localized.

Arctic Gas has stated that facilities will be maintained at least 2.5 miles from known peregrine falcon nesting sites, to the extent practicable. On the original prime route, there are two peregrine nesting sites within 3 miles of the route. On the cross-delta alternative, the route lies less than one mile from a traditional peregrine falcon nest site. Dr. Gunn suggested site-specific adjustments to protect raptors. Arctic Gas witness Randall Gossen testified that engineers will take Dr. Gunn's concern into consideration during final design. Since the number of Canadian Arctic peregrine falcons has declined from over 200 to 60 (28,377), it is expected that realignment to avoid the nesting sites will take place.

F. El Paso-Technical Feasibility and Construction Schedule Pipeline.

El Paso proposes to transport natural gas 800 miles due south from Prudhoe Bay, liquefy it at a plant in a seismically active area, load the LNG onto 165,000 cubic meter tankers, transport the LNG in these tankers 1,900 miles to a point in California and unload the LNG into a regasification plant also in a seismically active area. To find that it can do so within the 5-6 year overall schedule -- at the capital cost projected and with the system reliability required by an energy-delivery system transporting a substantial part of the U.S. energy supply -- requires an analysis of a number of engineering and geotechnical designs. These include a range of considerations involving geotechnics (frost heave, permafrost, soil data and slope stability), seismicity, liquefaction (design, storage and marine terminal), pipeline design and alignment (including realignment case), logistics, water availability, gravel supply, glacial impact, and pipeline crossings of streams, roads and other pipeline crossings, etc. As with Arctic Gas, the most significant considerations are discussed below.

LNG is a natural gas cooled to -259°F. so that it forms a liquid at approximately atmospheric pressure. As it becomes liquid, it reduces in volume some 600 fold, thus becoming sufficiently compact to make both storage and long distance transportation economically feasible. Natural gas in its liquid state at present has no practical use but must be regasified and introduced to the consumer at the same pressure as other natural gas. The cooling process does not alter the gas chemically in any way, and the regasified LNG is indistinguishable from all other natural gases of the same composition. Essentially, LNG is transported as a liquid at close to atmospheric pressure in cryogenic carriers -- similar to iced tea in a thermos bottle or more like liquid oxygen in a Dewar flash recalled from high school science classes.

1. LNG Safety

LNG is neither poisonous nor a pollutant and is neither more difficult to handle nor contain than any other liquid hydrocarbons either under pressure or in cryogenic containers.1/

1/ No party has raised the question of LNG technology safety until the closing briefs of the California State Commission and the Conservation Intervenors did so in an almost off-handed manner. Consequently, it was not briefed, although it could have been, in the Engineering Briefs. El Paso, in another excellent demonstration of its anticipation of issues and attention to detail, filed a 55-page response 8 days later addressing all LNG safety issues except risk analysis. El Paso's brief contains a wide range of technical summaries of the properties of LNG (pp. 2-16).

Except for fire hazard discussed below, it is less hazardous to handle from health, environmental and reactiveness than most chemicals. Its handling and transportation history, aside from a tank material failure in an uncontained facility during its infancy causing multiple deaths in Cleveland in 1944, has been exemplary for the last 30 years. Literally, hundreds of installations now exist worldwide--with the preponderence being in the U.S. and Canada--and the technology of LNG handling is both proven and reliable. The evidence of record here shows that LNG technology exists which will permit the safe design and operation of the facilities proposed to be constructed by El Paso and Western LNG. Due to the complex nature of the facilities, however, there are possible reliability risks of substantial plant outage, discussed _infra_, but they are not related specifically to LNG technology.

This is not to say that LNG is not a hazardous substance to be treated with great respect and warranting the highest level of safety precautions. It, like its close cousins LPG and the range of napthas, is highly flammable under certain conditions and if not properly contained could cause great damage. 1/ This stems from its high Btu content, its propensity while a liquid or a heavy vapor to collect in low places, and its rapid vaporization when in contact with a heat source. Since LNG is stored and transported at -259 degrees, both land and water are huge heat reservoirs which generate high initial, and in the case of water, sustained rates of LNG vaporization. LNG will burn only at certain air-gas mixture levels, the so-called flammable limit, and can be ignited readily at that level. There is no evidence that it will explode unless the gas is confined.

The greatest danger from an LNG accident is the formation of a large vapor cloud which could be ignited just before it becomes too diluted by mixing with air and becomes too lean to support combustion. An LNG fire at the moment of release of LNG would be located only at the source and would damage, assuming it were not in a containment area, only the facilities at the site. The fear raised by those opposing LNG facilities in populated areas requires, therefore, certain assumptions. First, there must be a large spill; second, no ignition at the time of the spill; third, a large vapor cloud formed; fourth, no ignition of the vapor until it had reached its largest proportions; and, fifth, ignition of the vapor cloud at its maximum size immediately before it would become too dilute at the fringes to support combustion.

1/ Western LNG, Staff and DOI all either presented evidence or discussed the problem attached to LNG handling and safety. See discussion _infra_, in California plant siting.

For maximum possible damage, however, several more assumptions must be made. There has to be little wind, since wind will disperse the gas rapidly. There must be an unlimited supply of heat -- a spill on land, for example, would rapidly cool the land, reduce transfer of heat, limit vaporization, and consequently reduce the size of the vapor cloud. There must be no source of ignition while the cloud is spreading over the terrain, including populated areas, until the vapor cloud has reached maximum size. One last rather critical assumption generally has been made by those engaging in risk analysis of LNG spills. Most LNG facilities, even in populated areas, are located in industrial areas and there are few people within a one-half mile or a mile. A small spill, or one quickly ignited, therefore, is not dangerous to the general population. In order to achieve the large size vapor cloud necessary to create even measurable risks for people located some distance away, an assumption has to be made that a huge volume of LNG be released instantaneously, but that it be done by a force which causes no spark to ignite the escaping vapor. The instantaneous spill can be envisaged as a Dixie cup filled with 10,000 cubic meters (a room about 70 feet wide x 70 feet long x 70 feet deep) suspended over the ocean.1/ A large hand now removes the Dixie cup and the LNG whooshes of a sudden into the ocean. In other words, the risk analysis is not realistic; it is a textbook analysis since only in textbooks can one envisage the removal of the container, such as a ship's hold or the contents of a storage tank, in the manner proposed.

The risk at the Oxnard LNG plant, as discussed <u>infra</u>, to a person 5/8 of a mile away from the LNG terminal was about 7 times less than the risk to the same person of being electrocuted by faulty wiring when flicking a light switch in his residence. To restate the initial premise, LNG is hazardous and must be treated with respect. The risks associated with its use must be analyzed. But, they must be done so on a credible basis with assumptions that are in themselves credible, and much of the risk analysis has not been done on that basis.

2. <u>LNG Technology</u>

El Paso's LNG system includes three main components: liquefaction plant and storage tanks, a marine terminal, and a fleet of cryogenic tankers. The general tenor of the engineering criticism of this LNG system goes not to basic feasibility which is now used worldwide, but instead to the degree of reliability,

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1/ The Western LNG analysis uses an instantaneous spill of 37,500 M^3 (a single LNG ship tank), 88,000 M^3 (a single LNG storage tank at Oxnard, and 352,000 M^3 (all 4 Oxnard storage tanks) (WL-51 8-78.) WL-51 is a several hundred page volume prepared solely as a risk analysis for the Western LNG terminal at Oxnard.

efficiency, and economics of this plant at this location. The three components are briefly described seriatim.

a. Liquefaction Plant

Liquefaction of the Prudhoe Bay gas at the Gravina Point plant is accomplished by the "Phillips Optimized Cascade Cycle" system. During the hearing, El Paso presented a modified gas turbine design (MOD POD) within its LNG plant design which it asserts will reduce turbine fuel consumption by some 35% over the original design. Under the 2.4 Bcf/d alternative the plant would consist of six independent parallel processing trains (8 trains under the 3.2 Bcf/d alternative), each train with an inlet design flow rate of 421.88 MMcf/d. Each train would contain three processing units: a diglycolamine gas-treating unit in which the CO_2 is removed to prevent deposits in the cryogenic equipment; a molecular sieve gas dehydration unit in which the gas is dehydrated to prevent moisture freezing in the cryogenic equipment; and the Phillips Optimized Cascade Cycle liquefaction unit which reduces the feed gas temperature by first sequentially subjecting it to propane, ethane and methane refrigerants and then flashing it to remove nitrogen. As the LNG is manufactured, it would be pumped into the four 550,000 barrel cryogenic storage tanks (a total capacity slightly exceeding two tanker loads) to await loading into the cryogenic tanker.

b. Marine Terminal

The LNG would be pumped from the storage tanks and loaded onto the cryogenic tankers through the marine terminal, which is comprised of the following major components: two berths for the cryogenic tankers; deck; 1,200-foot levy trestle for LNG pipeline and vehicular traffic; loading platform; loading arms; LNG load and return systems (capacity of 58,000 gallons per minute to each ship); tower and control house; and berthing and mooring dolphins.

c. Cryogenic Tanker Fleet

The LNG carriers (11 ships under the 3.2 Bcf/d case or 8 ships under the 2.4 Bcf/d case) each would have an LNG capacity of 165,000 cubic meters. Assuming Gravina Point and Point Conception as the terminals and an average service speed of 18.5 knots, each ship can make the 3,804 mile round trip in 11.5 days.1/ With each ship operating 330 days per year, the 11-ship fleet would theoretically transport 308 loads of LNG annually. The double hull, double propeller, 1,002-foot long and 150 foot beam tanker could employ any of five LNG containment system designs.

1/ 18.5 knots apparently is in calm water under assumed test conditions (52/7758). See, infra.

Although its LNG plant would be the largest ever constructed, El Paso contends that its design is not beyond the current state of the art and can be "scaled up" for commercial operation. In particular, El Paso stresses the modular nature of the plant (eight or six independent parallel trains), as well as the fact that each element in the trains has been tested and is in commercial operation. Likewise, El Paso contends that it is capable of "scaling up" its current 125,000 cubic meter cryogenic tanker technology to the 165,000 cubic meter design required in this case. In this regard, it notes in particular that the "block coefficient" is substantially the same between the existing 125,000 and the proposed 165,000 cubic meter tankers and that the additional 40,000 cubic meters requires only a few more feet of length and beam. El Paso concludes from its computer simulation techniques, discussed infra, that the proposed fleet can handle 105% of the LNG plant's capacity and that, with only 10 of the 11 ships proposed for the 3.2-Bcf/d case, the fleet could handle 98% of the output for 3 years. El Paso claims that the LNG plant and tanker fleet, because of the operational flexibility designed into them, are successfully integrated. For example, it counters the attack that LNG production during periods of delayed ship arrivals will often exceed 300,000 cubic meters of storage capacity by asserting that this would only occur 12 times a year and that its storage design capacity of about 350,000 cubic meters provides an adequate margin of flexibility.

Arctic Gas levels a number of attacks at El Paso's LNG technology in an effort to augment the perception of risk involved. To begin with, it points out that the Phillips Optimized Cascade Cycle process to be used in each liquefaction train has only been commercially applied one time, that being at the Marathon-Phillips Kenai, Alaska plant. Also, Arctic Gas warns that the 220% scaling up of the largest existing train (172 MMcf/d) to the proposed 370 MMcf/d utilization is commerically unproven. It echoes the same thought with respect to the cryogenic tankers. Related to this theme of uncertainty, Arctic Gas interjects, are the additional design innovations made by El Paso (pure ethylene in lieu of methane/ethane second stage refrigerant, refrigeration heat exchange nearer to thermal equilibrium, combined cycle-gas/steam-turbine-mechanical compressor drive) in the name of improved fuel efficiency. Arctic Gas contends that these innovations would increase the system's complexity and sensitivity to abnormal operating conditions. Expanding on this theme even further, Arctic Gas challenges the predicted 99.5% reliability of El Paso's MOD POD because the recent advances in gas turbine technology employed therein have very little operating history. Moreover, it considers El Paso's efficient fuel usage (only 5% of inlet volume as opposed to 14% at the Kenai plant) theoretical, at best, and based on estimates abstracted from an engineering calculation.

Arctic Gas concludes by doubting the successful integration of LNG plant and tanker fleet. It views the 2-day storage capacity inadequate in light of the average tanker arrival interval of 1.2 days; that is, any delay increasing the interval to over 2 days would force a reduction in LNG production. As a related matter, Arctic Gas finds imprudent El Paso's plan to run the liquefaction plant at 105% of design capacity overtime to make up any reduced production, since the LNG plant manufacturer would not guarantee such overcapacity operation. Arctic Gas reasons therefrom that El Paso would have to design for such extra capacity, which of course means greater capital costs. Alcan also doubts El Paso's ability to scale up and integrate its LNG plant and tanker fleet.

In order to adapt the LNG process to the transportation of the tremendous daily quantities of Prudhoe Bay gas, El Paso has had to greatly expand upon the design of commercially applied technology. In an effort to overcome the inherent LNG operational problem of altering the physical state of the gas, El Paso has not only greatly increased the capacity of each liquefaction train but also initiated a number of design changes, including MOD POD, to improve fuel efficiency. There have been no serious questions raised as to whether this system could function. From the LNG point of view, it can be built. But El Paso's design approaches the "current state of the art," there being prototypes and successful commercial application of parts of its designs, but no entire plant which combines all these pieces. Although Mr. Pasek testified that on the basis of his experience he believed that the design figures for full usage at the LNG plant could be computed "within 95% order of magnitude" (47/7079), it is impossible to state with confidence, for the reasons stated below, that El Paso can achieve the fuel efficiency rate and operational performance claimed.

To begin, El Paso will substantially improve upon the 14% Btu shrinkage at the Kenai plant, which also employs the Phillips process, whether or not it achieves only the 5.44% shrinkage claimed. This improvement in liquefaction process fuel efficiency results from differences between the Kenai plant and El Paso's project which do not depend solely upon advanced design modifications: (1) the chemical makeup of Prudhoe Bay gas (substantially more of the heavier hydrocarbons than the almost pure methane composition of the Kenai gas) requires approximately 15%

less horsepower to liquefy than the gas for the Kenai plant, and (2) combined cycle turbines to drive the compressors are more efficient than the single cycle turbines employed at the Kenai plant (170/27,943-27,944).

However, the producers have stated that they will reserve the right in contracts with shippers to extract liquid hydrocarbons from the gas stream, and the State of Alaska has asserted that it wants the extraction plant built in the State. If the extraction takes place upstream of the LNG plant, that portion of the increased LNG plant fuel efficiency resulting from advantageous intake gas composition would be lost. If, on the other hand, the extraction takes place within the LNG plant, the overall plant fuel efficiency may not suffer, although the allocation of fuel between the liquefaction process and the extraction of liquids could produce the same efficiency loss assessed against the liquefaction process. In either event, gas consumers would not realize the full benefits of the LNG plant efficiency claimed by El Paso.1/

3. Seismicity

a. Pipeline Fault Crossings

Earthquakes, and their consequences are a fact of life for any trans-Alaskan project seeking an ice-free warm water port in southern Alaska. The El Paso pipeline traverses seismically active areas, especially in south-central Alaska. Based upon Alyeska fault rupture hazard studies El Paso has identified only three active linear features (faults) crossed by its pipeline which would require special design, those being Donnelly Dome (MP 542), Denali (MP573) and McGinnis Bay (MP582).2/ It rejects as unsupported by the evidence claims of numerous faults in the Chugach Mountains, although it concedes that this region should and can be studied and necessary specifications developed within 1 year before completion of its final design. It concludes by specifying the special design precautions to be employed for the pipeline crossing these three active faults: heavy wall pipe;

1/ It is recognized, however, that there might be minor offsets to the cost effect of such loss in LNG plant fuel efficiency, such as slight reductions in El Paso's cost of displacement delivery of leaner gas within the lower 48 states.

2/ El Paso found no reason to design against the following faults because of their alleged inactivity or remoteness from the alignment: Clearwater, Landlock, Bagley, Chugach-St. Elias, and Ragged Mountain.

sloping side walls in ditch; selective backfill and loose gravel; and shutoff valves on either side of the fault zone at highway crossings. In the case of the Denali fault crossing, El Paso states that the design is to an 8.5 Richter scale seismic event.

Arctic Gas, Alcan and Staff argue that El Paso did not prepare extensive seismic studies before preliminary design and cost estimates, contending that it is therefore impossible to verify El Paso's design costs. They then attack in general terms El Paso's major fault crossing designs, pointing out that fault motion of up to 20 feet must be designed into the pipeline. They, moreover, then raise the problem of repair time in that many of the active seismic zones crossed by El Paso are mountainous, thus having the potential for landslides accompanying a seismic event. In addition, Staff points to the alleged numerous faults in the Chugach Mountains including Gravina Point, which must be, but have not been, designed against.

El Paso has identified the three major active faults dictating special design precautions, those being Donnelly Dome, and Denali, and McGinnis Bay (ST-19, p.263; 157/25,932-25,933; 164/26,965-26,966). The evidence shows that the design precautions employed by El Paso, such as an 8.5 Richter scale design for the entire length of the pipeline, loose granular backfill and double-thickness pipeline walls crossing major faults, factoring in 0.75g, not just 0.6g, acceleration, and automatic shutoff valves are appropriate and should prevent substantial damage and service interruption from a design seismic event (an earthquake registering 8.5 on the Richter scale with ground movement up to 20 or 30 feet horizontally and 5 feet vertically) (42/6298-6299, 6300-6304, 6308-6309). While there is evidence that additional studies will have to be undertaken and that additional design precautions are necessary (157/25,922-25-923), there is no way to quantify this effect and they do not appear to seriously affect El Paso's ability to meet its estimated construction schedule (169/27,702; 154/25,434). For example, the seismic makeup of the Chugach Mountains cannot be ascertained from the conflicting testimony herein (157/25,936-25,937; 164/26,967-26,969), and El Paso would have to accomplish site-specific geotechnical research through that region before completing its final design. El Paso has left a full year for basic additional analysis and design and, while difficult, it is likely that sufficient seismic analysis can be performed and design precautions incorporated in the final pipeline design within that period of time -- at a cost.

b. <u>Gravina Point LNG Plant Site</u>

El Paso has designed its Gravina Point LNG facilities to withstand an earthquake of 8.5 Richter scale intensity and 0.6g ground acceleration (components not exposed to LNG are designed to withstand 0.3g bedrock acceleration), conceding that the

Prince William Sound region is susceptible to substantial seismic activity. It advances several arguments in support of this design, which it views as conservative. To begin with, this 8.5 magnitude is the magnitude of the 1964 Alaskan earthquake (the most severe earthquake reading ever recorded), and it asserts that the recurrence interval for an 8.5 magnitude quake in Alaska is 200 years. In addition, El Paso finds that the site is underlain by competent, very dense bedrock (found from the surface to 40 feet below the surface) which is highly significant in light of the fact that very little damage was suffered by structures founded upon competent bedrock during the 1964 Alaskan earthquake. El Paso moreover attempts to refute any suggestion of possible ground rupture near the site, alleging that literature and field research indicate no faults at or near Gravina Point which were active in the 1964 quake. El Paso discounts several regional faults because of their inactivity and/or their distance from Gravina Point (Bagley, Patton Bay, Hanning Bay).

Based on these considerations, El Paso asserts that there is no appreciable risk from an active surface fault which would cause ground rupture at or near the site. It emphasizes that the cause of the 1964 event, an active megathrust fault underlying all of south-central Alaska, is the only real seismic risk to the Gravina Point site and that its seismic design parameters (8.5 magnitude and 0.6g ground acceleration) are more than adequate to absorb the impact of such a megathrust event. During the 1964 event, the site area was uplifted 4 feet and the entire southern Alaskan coastal area shifted horizontally 30 feet, but there was no ground failure. El Paso notes that the epicenter of the 1964 earthquake was about 50 miles from the Gravina Point site and contends that, at such a distance, the ground force acceleration of the 8.5 magnitude quake would be much less than 0.6g. The 1964 earthquake resulted in 0.16g acceleration of the site. The 0.6g is the level of shaking which could result from an 8.5 earthquake of an epicenter 20 miles away. El Paso also argues that the only other source of an 8.5 magnitude event would be major surface faults, but that the nearest such faults -- Chugach-St. Elias and Patton Bay, are more than 50 miles away. Therefore, the impact would be too attenuated at Gravina Point to approach design magnitude.

El Paso intends to conduct further tectonic investigations at the site within the 1-year period needed to finalize the design, although it maintains that its cost estimates for the LNG facilities remain valid. It states that it has already included the time and money needed for that final design in its estimates.

Arctic Gas assails the sufficiency of El Paso's seismic design by first emphasizing the absence of both seismic design studies for Gravina Point and competent seismic engineering which, in its view, necessarily preclude any Commission finding that El Paso's facilities could withstand a large magnitude earthquake and that its cost estimates are reliable. Arctic Gas stresses the need for El Paso to undertake substantial seismic research and design, in part necessitated by El Paso's alleged failure to consider other seismic factors beside 0.6g ground acceleration in its preliminary design.1/ Such research would take a year or more to complete. In particular it refers to El Paso's design change from 0.3g to 0.6g acceleration during the hearing for the marine terminal as an example of the impossibility of accurately assessing El Paso's cost estimates.

Staff's major difficulty with El Paso's seismic design is its preliminary and inadequate nature, which Staff views as precluding meaningful analysis of its project costs. In addition, Staff raises the specter of ground faulting offshore (within 2 miles) and inland near the site. It also echoes many of the concerns expressed by Arctic Gas. Alcan on brief reiterates in general terms the seismic risks faced at the Gravina Point site.

Preliminarily, not only is it uncontroverted that the entire south-central coastal area of Alaska, including Prince William Sound, is an area of significant seismic risk, it experienced in 1964 an earthquake which had the greatest magnitude ever recorded anywhere. The location of El Paso's LNG plant, storage tanks and marine terminal, due to the sheer volume of the gas involved and the basic nature of the cryogenic process, mandate comprehensive and reliable seismic design based upon creditable risk analysis to insure against a seismically-caused disaster or even substantial service interruption. It is clear that El Paso's existing design will require substantial upgrading and El Paso must provide additional seismic certainty in its final design following certification. What must now be determined is whether El Paso, within the time available, can complete its final design to guard against the magnitude of seismic events which could strike Gravina Point and, if so, how much more this will cost.

As found below, El Paso's timing and cost estimates following final design could well differ from its present estimates, but its preliminary seismic analysis is sufficient to warrant finding that the Gravina Point design and cost estimates are

1/ Arctic Gas believes that cryogenic temperatures and rotating equipment necessitate deeper analysis than merely relying upon designs for 0.6g ground acceleration. Dr. Nathan M. Newmark (157/25,949).

reasonably accurate. (164/27,012-27,013)1/

El Paso has in fact designed its Gravina Point LNG facilities for an 8.5 magnitude earthquake and 0.6g ground acceleration. It was reasonable for El Paso to base this design, 8.5 magnitude, upon the 1964 earthquake, which is the only recorded 8.5 magnitude event (59/5055). El Paso heavily relied upon Alyeska and U.S.G.S. studies which are substantial and of great value (164/26,984). Whether such a design event were to occur from an active megathrust fault (164/27,003-27,004; EP-240) as in the 1964 earthquake, or from one of the known active surface faults in the Prince William Sound region, El Paso's seismic design appears adequate. (8.5 magnitude and 0.6g acceleration) (157/25,938). The epicenter of the 1964 earthquake, being 53 miles from Gravina Point, resulted in a ground acceleration at Gravina Point of much less than 0.6g (164/27,030). If it is assumed that there is accessible and competent bedrock at the site upon which the facilities are to be founded (59/8918-8920-9018; EP-143-40 and 43; 60/9092-9093, 9095), this should further attentuate the ground acceleration (59/9060-9062; 164/26,978).2/ It is unlikely that a future 8.5 magnitude event with an epicenter closer than that of the 1964 event would surpass the 0.6g ground acceleration design. Moreover, the major surface faults in the region, such as Bagley, Patton Bay and Hanning Bay, are sufficiently distant from Gravina Point to attentuate the impact at the Gravina Point site of any conceivable 8.5 event at those surface faults. (59/9062-9064; 164/26,994-26-995, 26,998-26,999, 27,017; EP-240). There was no probative evidence warranting even a suggestion of an active offshore fault within 2 miles of the site.

Even assuming a recurrence interval of less than 200 years for the 1964 event (59/9047, 9052-9053), El Paso's seismic design is adequate. Although Arctic Gas has raised the question that additional seismic factors must be considered, such as special design for cryogenic and rotating equipment (157/25,938), there is no real indication that redesign along those lines would substantially increase costs (60/9091; 170/27,966-27,970). Furthermore,

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1/ It is difficult totally to accept at face value Mr. Tseklenis' sanguine analysis and criticism of Dr. Newmark (179/27,917). As elsewhere, all costs, whether previously provided or not, are considered by Fluor as having already been factored into the equation. Surely, in this multibillion dollar project, Fluor missed something!

2/ The studies made by El Paso showing bedrock close to the surface were minimal, although its witnesses claimed their observations, though brief, were accurate. If corings should reveal sedimentary deposits under what appear to be bedrock, as was experienced at Valdez by Alyeska, costs would be higher.

the time and expense of further seismic studies preceding final design is not a real problem for the study will be included in the already scheduled and budgeted geological and geotechnical studies. (164/27,004-27,006, 27,012, 28,060).

The only possible seismic risk which could completely preclude use of the Gravina Point site is the possibility of active ground rupture at or very near the site, although the discovery of incompetent rock could suggest cost overruns for seismic design and construction which would prove unacceptable. El Paso before final design must continue to assess this possibility, even though there is no indication that it in fact exists (59/9066-9068; 164/26,978, 27,023-27,024). Another indication that there are no surface faults in Gravina Point is that Harris Creek waterfalls do not suggest being fault-controlled (164/27,014-27,015).

c. Tsunamis and Seiches

Major seismic activity can give rise to seismic sea waves known as tsunamis (gravitational sea waves produced by any large-scale, short duration disturbances of the ocean floor, principally by a shallow submarine earthquake) and seiches (free or standing-wave oscillations of the surface of water in an enclosed or semi-enclosed basin). El Paso asserts that the effects of tsunamis and seiches at Gravina Point would be minimal, pointing to the experience of the 1964 earthquake. While seiches were generated in Prince William Sound, USGS found no evidence of significant seiches at Gravina Point.

El Paso explains this conclusion of minimal impact at Gravina Point by first contending that, since large tsunamis need a large area in which to generate (400 kilometers in diameter); the 100 kilometer diameter of Prince William Sound precludes them, and that, as with the 1964 earthquake, major tsunami waves entering Prince William Sound from the open ocean would be substantially reduced by the numerous islands therein. In addition El Paso asserts that major tsunami waves approaching the LNG site would be diffused by the drag effect of the bottom of Orca Bay. Finally, it contends that tsunamis give adequate warning of their approach.

Turning to seiches, El Paso concedes that during the 1964 earthquake landslides and submarine slumping of loosely consolidated materials in constricted bays in Prince William Sound generated such seiche waves with no warning; however, it asserts that studies have shown that no such landslide and submarine slumping exists at or near Gravina Point. The closest unstable sediment is 18 miles away. This, according to El Paso, would result in seiches reaching Gravina Point which were substantially attentuated by the expanse of Orca Bay and the irregular shoreline. Accordingly, El Paso contests Staff's FEIS statement of 30 foot high waves at Gravina Point. El Paso concludes from the above that its design of the marine terminal is more than adequate, asserting that the larger tsunamis give enough advance warning for a berthed cryogenic tanker to depart and that the seiche waves, while not providing enough time, are too small to cause substantial damage.

Staff, Arctic Gas and Alcan again raise the criticism of insufficient background studies for El Paso's seismic design, this time pointing to the possibility of tsunami and seiche waves generated within Prince William Sound which could exceed El Paso's present marine terminal design for sea waves. Arctic Gas questions El Paso's reliance upon the sea wave activity from the 1964 earthquake (it occurred at low tide and caused the land to rise 4 feet), and it suggests the possibility of 65 foot tsunamis and 25 to 30 foot seiches, which were recorded elsewhere in Prince William Sound, hitting Gravina Point. It also emphasizes the rapid generation of seiches, thereby casting doubt upon El Paso's 12 foot wave design for the occupied terminal berths since the tankers would not be able to depart in time. On this same point Arctic Gas and Alcan challenge ElPaso's rationale for the less substantial design for the occupied berth (the cryogenic tanker would allegedly act as a buffer for the terminal) as unfounded.

El Paso's marine terminal design appears adequate to withstand the sea waves generated by earthquakes. While an 8.5 earthquake is theoretically capable of producing tsunami waves of 65 feet (EP-72, Table 3), it is undisputed that the location and local bathymetry of Gravina Point will expose the site to a much smaller wave. The FEIS states that the maximum expected tsunami wave heights at Gravina Point are 20'-30', with a maximum run-up of 34'.1/ This is inaccurate, however, for it is based upon experience at Orca Inlet, which is significantly different. El

1/ Run-up is what happens when a large wave hits the shore and the wave action moves far inland.

Paso has designed its marine terminal for a tsunami wave of 20' if a ship is not in berth, and a wave of 12.5' when a ship is at berth. The different tsunami wave criteria are used because El Paso believes that an earthquake that would generate 20' waves would give sufficient notice to remove the ship from berth before the wave approaches: It will take 20 minutes for a tanker to depart (54/8007).

The Gravina site was relatively unaffected by tsunamis in 1964 (94/14,427; 165/27,007). The effects of the waves were reduced considerably as they approached the shoreline. Specifically, they were mitigated by the presence of islands that occur around the entrance to and within the Sound. There are also several existing conditions at Gravina Point which would tend to dissipate waves: There is shallow water which increases drag and tends to reduce wave height; there is a broad basin forming the approach to the site; eastern Prince William Sound has excellent energy-absorbing characteristics, because of its many inlets, bays, etc; and the Gravina Point facilities are oriented such that waves would parallel the shoreline on the axis of the vessels, rather than frontally into the site.

El Paso's 20 foot design was postulated upon the generation of a wave outside Prince William Sound. A berthed ship would have 20-30 minutes warning before such a wave reached the site. This would be sufficient time to allow vessels to depart. The FEIS agrees that a wave generated outside Alaska would probably give sufficient notice to allow a tanker to be removed. The FEIS also states that onshore facilities are clearly at a sufficient elevation to withstand worst case conditions. However, the FEIS warns that if the wave is generated in or near the Sound, it is unlikely that the tanker could be so removed, and "it is possible that the vessel and terminal facilities would be destroyed by the design wave if the ship were still berthed." (ST-19, II-268).

There is, however, no factual basis for this Staff concern. Tsunamis generated in Prince William Sound, while having a much shorter time interval before reaching the site, would also be much smaller waves. In order to generate a large tsunami, there must be a larger area to generate the wave motion (60/91111-9112). In order to generate a large magnitude tsunami, such as that associated with an 8.5 magnitude earthquake, the dimensions of the tsunami source must be in the order of 400 kms in diameter.

Prince William Sound is about 100 kms in diameter. However, there is no specific evidence concerning the maximum tsunami wave that could originate within or near the entrance to the Sound. There is some evidence that a 20' design wave would create a lesser load on the facilities than the loads from the ships during berthing, (94/14,458). Even though it would be advisable and prudent for El Paso to redesign the marine terminal when the berths are occupied for a 20 foot design wave, the evidence shows that such redesign should not significantly affect its costs or scheduling.

As already indicated by recitation of El Paso's arguments, the 1964 earthquake caused massive submarine slidings of loosely consolidated materials in several restricted bays in Prince William Sound. These landslides in turn generated seiche waves. Since the slumping occurs simultaneously with the earthquake, there is much less warning of a seiche than a tsunami. There is no evidence that Gravina Point was affected by seiches in 1964 and, furthermore, there is no indication that they will be triggered in the future. There is also an apparent absence of significant unstable unconsolidated material in the site area, and in the relatively open, unconsolidated morphology of Orca Bay. Thus, there are no areas which would be able to provide a substantial amount of sediment for a submarine slide or other cause of a sea wave within about 18 miles of the site. El Paso's conclusion that any seiche would be attenuated as it traversed the wide Orca Bay region is supported by the evidence. (59/9035-9039).

4. Realignment Case

Under its base case alignment El Paso's pipeline would run basically parallel and close (within 3000 feet for 85% of the 766 mile distance) to the Alyeska pipeline and haul road. During the hearing the State of Alaska urged preparation of a realignment of this route in order to greater utilize existing Alyeska haul road and facilities, to which El Paso acceded by its evidentiary filing of May 18, 1976. Under El Paso's realignment case it would use Alyeska work pad or haul road, with some widening of each, for 79% of the route. This realignment would add 13.8 miles to the pipeline. It would also eliminate the need for snow roads or work pads.

While El Paso has accompanied its realignment case with some studies which assert that it is feasible, it has never supported the realignment. It will build it if certificated. It notes the potential for thermal interference between Alyeska's hot oil line and its chilled gas line but only when both are buried, concluding however that thermal interference can be avoided by insulation and placement of the pipelines.

Staff actively opposes the realignment case, first of all because of the chance of rupture of the Alyeska line due to blasting (stringent controls would be required), collisions from heavy equipment passing along or under the Alyeska line, and other construction activities. (ST-51) Not one person, excluding the State, who has the right to permit such realignment has agreed that it is feasible, much less particularly desirable (neither Alyeska, DOI, or DOT pipeline safety). In addition, unless Alyeska is convinced that construction and burial of the line will not affect its vertical support members, it is difficult to see how it could, much less would, permit construction, And, of course, Alyeska might wish to be paid for its 650 mile long gravel pad. In addition, Staff contends that the realignment would cost another $200 million due primarily to the need for thicker walled pipe where it runs adjacent to the haul road and for more gravel.[1/]

A review of the evidence accompanying the realignment case (169/27,698-27,705 (Wright); 169/27,706-27,710 (Murphy); 169/27,711-27,716 (Winn); EP-242, 243, 251, and 252) does not warrant a finding that El Paso's certificate application should be amended to incorporate the realignment case. At the time of construction Alyeska will carry 1.5 million barrels per day of hot oil, half above ground. Although geotechnical redesign could most probably eliminate the thermal interference between the heated and chilled pipelines (contact of thaw and frost bulbs), a combination of the additional costs of realignment and the serious threat of damage to the Alyeska line from even strictly regulated El Paso construction and operation compels the conclusion that only El Paso's base case alignment should be considered. When balancing the liabilities of the realignment against any possible benefits, it must be remembered that the environmental benefits purported to flow from close corridor alignment have already been found not to exist and the basic construction and logistic benefits which clearly exist will be just as available to the base alignment as to the realignment case.

5. <u>Glacial Impacts</u>

a. <u>Columbia Glacier</u>

In choosing the Gravina Point site, El Paso anticipated that icebergs emanating from the Columbia Glacier, the terminus of which on Prince William Sound is west of Valdez, would pose no threat to its LNG fleet. In that no icebergs have been spotted in the proposed tanker shipping lanes, El Paso maintains

1/ An exception to this requirement would be sought, but there is no indication that DOT would grant it.

this position. It is well founded. Staff takes the position that variations in the prevailing currents and changes in the Columbia Glacier could lead to increased risk of cryogenic tanker accident.

Notwithstanding Staff's concern expressed in the FEIS concerning Columbia Glacier-propagated icebergs impinging upon the LNG tanker shipping lane, there is no hard evidence warranting this concern. In choosing an LNG terminal site El Paso was concerned about icebergs (51/7591), and it found no evidence of icebergs along the shipping lanes to Gravina Point (51/7594; 60/9118-9119). El Paso correctly explained this absence of ice in the southeastern portion of Prince William Sound as caused by the prevailing currents which now carry ice from the Columbia Glacier to the west of the LNG shipping lanes (51/7593, 7597), notwithstanding possible temporary current changes due to certain unusual weather conditions.

b. Surging Glaciers

El Paso's alignment through the Chugach Mountains passes very close to a number of small glaciers. It defends this proximity to glaciers on the grounds that these glaciers have been receding for a number of years and that it takes a long time (longer than the life of this project) for a receding glacier to become a surging glacier. 1/ Arctic Gas' rejoinder is that El Paso has failed to undertake the site specific work necessary to assure that its pipeline would not be endangered by a glacier. In light of the proximity of the alignment to these glaciers and the chance of surging, Arctic Gas would assign the burden of disproving this risk to El Paso, a burden allegedly not satisfied.

Despite the proximity of El Paso's alignment to several small glaciers in the Chugach Mountains (61/9301), the risk of pipeline destruction from a possible glacial advance, including a surge, is minimal (61/9307; 62/9465). The glaciers involved have been receding for many years and the transition from a receding to a surging glacier is not rapid, in fact highly unlikely within the life of this project is most cases. (61/9301-9302, 9306; 62/9475). Nonetheless, in light of the absolute nature of pipeline destruction of up to several miles due to

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1/ A surging glacier is one which becomes plastic and rapidly advances - moving sometimes hundreds of feet per day.

possible glacial movement (61/9303-9304), El Paso should conduct additional glacial analysis before finalizing its design. A more precise understanding of the probability of any of these glaciers surging is required before final design. El Paso has the flexibility to change its route alignment around these glaciers (61/9308).

6. Frost Heave, Soil-Core Samples, and Slope Stability

El Paso has not yet conducted a soil core sample investigation along its proposed right-of-way through Alaska, specifically addressed frost heave in its design, or performed site-specific slope stability analysis except through general reconnaissance. El Paso justifies the adequacy of its preliminary pipeline design, however, by stressing that it employed one of Alyeska's design engineering companies, Pipeline Technologists, Inc., to prepare its preliminary design. El Paso expresses confidence in its design due to its analysis of Alyeska's 1200 core hole samples from an alignment basically parallel to, albeit not the same as its own. It alleges that the remaining geotechnic data needed for final design can be amassed in twelve months and asserts that its construction schedule already includes both adequate time and money to complete its studies. The recent availability of the records of thousands of additional core samples, it argues, additionally will shorten this time requirement. For the 43 miles that its alignment diverges completely from Alyeska and crosses the Chugach Forest, El Paso asserts that Pipeline Technologists expended 1200 man-hours (30 man-weeks) on field reconnaissance.

While recognizing that the Alyeska core samples can aid in general design in similar terrain and soils, Staff and Arctic Gas warn that El Paso's reliance on Alyeska's geotechnic data is misplaced and that it must engage in site-specific core sampling along its base case right-of-way. Arctic Gas emphasizes that El Paso's base case alignment is separated from Alyeska by up to several miles in many locations; that this soil data is oftentimes inapposite because the hot oil Alyeska line had different geotechnic constraints affecting the alignment (Alyeska used unfrozen terrain as much as possible) than has El Paso's chilled buried line which should use frozen grounds wherever possible; and that El Paso's alignment traverses many different types of soil and terrain where rights-of-way core sampling are mandatory.

Whether Arctic Gas is correct that El Paso has performed no core sampling of its own is irrelevant since the controversy is joined over whether El Paso can rely upon Alyeska's geotechnic data, including Alyeska's 1200 core hole samples, and El Paso's own overview in formulating El Paso's alignment and determining its costs. This has been debated throughout the record. El Paso essentially is relying on soil data developed by Alyeska in building a pipeline through similar terrain and on its face this is not unreasonable (41/6052-6054; 154/25,444; 169/27,714, 27,772). There are, however, significant differences between Alyeska's hot oil pipeline and the buried chilled gas pipeline and these dissimilarities call into question whether data collected for one is more than generally useful for the other. If not, the final design could not be effected without extensive and time consuming site specific, mile-by-mile, right-of-way soil analyses, including a massive program of on-site core hole sampling (41/6057-6058, 6065, 6095; 169/27,773).

El Paso has also not yet specifically addressed frost heave avoidance in its design. It alleges that frost heave is possible for only 50 miles of its 809 mile alignment, as compared to 250 miles for Arctic Gas. As elsewhere, it promises to pinpoint frost heave areas and to reflect frost heave abatement to its final site-specific design by use of a mathematical model which it claims has been already proven effective. El Paso advances several remedial techniques which it allegedly is capable of instituting: use of non-frost susceptible granular backfill; burying the pipeline deeper, thereby applying greater overburden pressure; pipeline insulation; and pipeline anchors. It concludes that its present application already includes the needed time and money to accomplish the final frost heave design.

Arctic Gas begins by claiming that it alone has a working frost heave model and testing program and continues by deprecating the ability of El Paso's proposed model to predict frost heave and El Paso's proposed frost heave abatement measures. It characterizes this model as solely geothermal (temperature). It also questions El Paso's contention that frost heave analysis and abatement has already been included in its cost estimates since it has done nothing yet. Arctic Gas moreover contends that the El Paso alignment crosses 100, not 50, miles of frost susceptible soil.

Nor does the record show that El Paso in its field reconnaissance did much more than generally consider the slopes to be crossed and aligned the route accordingly. As with the general soil data question, El Paso also defends its reliance upon Alyeska slope stability experience. It concludes by again promising to complete site-specific slope analysis for its final design, pointing out that it has alloted funds for such remedial measures as riprap, gravel, retaining walls, revegetation, dike terraces, drainage and water diversion. Arctic Gas, however, contests El Paso's claim that it has already factored slope stabilization into its cost estimates since it has not fully analyzed the problem.

On balance, it appears that El Paso's present construction schedule can and does accommodate that additional geotechnical research time absolutely necessary before proceeding to final design and construction (41/6065, 6096, 6098). While it is difficult to evaluate how much of the 5% contingency in El Paso's cost estimates would be used up on its rights-of-way geotechnical design work, (41/6059-6060), these further studies are necessary and the cost will not be de minimis. In final analysis, however, it is too much to believe that all of this work could be accomplished on the accelerated time frame necessary to meet El Paso's schedule without costs which will exceed its flexible 5%.

7. Gravel Borrow

El Paso argues that Staff is wrong in its FEIS findings that gravel would be in short supply and El Paso may possibly require stream-bed gravel collection which would severely impact fish and water quality. (ST-19, p. 256). El Paso argues that Alyeska's estimated 189,000,000 cubic yard requirement turned out to be only 65,000,000 cubic yards; that El Paso's base case gravel requirements are only 6,545,000 cubic years and 16,400,000 cubic yards for its realignment case; that Alaska and the Department of the Interior have approved gravel sites containing 220,000,000 cubic yards; that the recognized gravel shortage north of the Brooks Range should not impede El Paso's North Slope construction because of the winter schedule which permits use of snow workpads; that the Department of Interior (for federal land) and Alaska (for state land) have complete control over gravel removal; and that it is anticipated that these governmental entities will have El Paso remove gravel from existing borrow pits. El Paso does, however, recognize the potential environmental impacts of siltation, erosion and aesthetic degradation flowing from gravel removal, but it feels that these can be successfully mitigated. Arctic Gas argues that El Paso has a gravel shortage, asserting that gravel supply must be considered regionally and that for the 200 miles from the Brooks Range to Prudhoe Bay gravel is in short supply.

The total available supply of gravel along the pipeline corridor appears to be sufficient to meet El Paso's overall requirements. It is also true, however, that there are localized and even regional gravel shortages. (ST-19, p. II-256; 145/23,495) In this latter regard, there is in fact a gravel shortage along El Paso's alignment on the North Slope for some 200 miles from the Brooks Range to Prudhoe Bay. (145/23,575-23,576). Although El Paso's use of snow workpads should reduce its gravel requirements on the North Slope, it would still need additional gravel for the maintenance of existing haul and lateral roads; therefore, additional studies must be forthcoming from El Paso on this matter.

8. Miscellaneous

On brief no serious questions have been raised concerning a number of aspects of El Paso's construction-logistics, estimates of water requirements and availability for snow road construction and hydrostatic testing (El Paso contemplates primarily air testing); design for crossing roads, rivers and other pipelines (predominately Alyeska which it does 26 times); and metallurgy and pipe availability. While a number of these issues were explored extensively on the record, such as air testing and water availability north of the Brooks Range, none would be a significant problem if proper planning were employed. Logistics along El Paso's route, in fact, would be relatively straightforward given both the North Slope producers' and Alyeska's pioneering.

G. El Paso -- Location of Alaska LNG Plant Site.

El Paso proposed Gravina Point, located on a peninsula extending into eastern Prince William Sound, as the site for its LNG plant in Alaska. Staff has proposed an alternative site, Cape Starichkof, in eastern Cook Inlet. Briefs have been filed by El Paso, Western LNG and the State of Alaska supporting Gravina Point, and by Staff and the Conservation Intervenors "opposing" the certification of Gravina Point. First, the burdens of proof which must be met by an applicant for a certificate of public convenience and necessity and a proponent of an alternative will be examined. Then evidence of record supporting the proposal and the alternative will be evaluated.

1. The Burden of Proof

The Commission has an obligation, both under the National Environmental Policy Act and the Natural Gas Act, to consider both an applicant's proposal and any viable alternative to the proposed projects or parts thereof. City of Pittsburgh v. FPC, 237 F. 2d 741 (D.C. Cir. 1956); 42 USC § 4332. As discussed more fully in the separate Environmental section, a "rule of reason" prescribes that the original proposal and alternatives be supported by an evidentiary showing and discussed in sufficient depth to permit the reviewer to make a reasoned choice. NRDC v. Morton, 458 F.2d 827 (D.C. Cir. 1972). There is no fixed quantum of evidence or specific level of discussion required as to each proposal; it is obvious that a proposal to do the absurd should not be accorded the same consideration as an alternative which recommends itself as reasonable on its face. 1/ But, while the standard is flexible, it is clear that an applicant has, at the outset, the burden of proving that its proposal can adequately serve the public convenience and necessity. It is equally clear that the proponent of an alternative has the affirmative obligation to independently assess that alternative, present supporting evidence in its behalf, and demonstrate that the applicant's proposal should not be certificated either because it is so flawed that it is unacceptable or the recommended alternative is superior. (18 C.F.R.

1/ The FEIS discusses "alternatives" to move natural gas from the North Slope by rail, blimp, gigantic submarine, ice-breakers, and methanol conversion.

§§2.80, 2.82; APA 556d) This is particularly true in the instant case, where the applicant has made a prima facie case for its proposal and the proponent of the alternative concedes that the applicant's proposal is indeed "acceptable" (ST-18, I-A10).

Staff, in fact, concedes that while given an ample opportunity, it has presented insufficient technical evidence on the record to support a Cape Starichkof certification. However, Staff suggests that Gravina Point should not be certificated, apparently based only on the existence of Staff's yet unproven alternative site at Cape Starichkof: "Staff is not in any case proposing Cape Starichkof, but opposing Point Gravina on the basis of its showing on Cape Starichkof." (Staff Reply Brief, 8) Where Staff has proposed an alternative but failed to adequately support it, there is no fairness or logic in shifting that burden back to the applicant. Staff's rationale, if accepted, would deny El Paso any semblance of due process without any showing that the decision maker would be serving the public interest by not certificating a proposal then supported by the evidence. An applicant which has met its burden for the proposal it supports should not be put in the position of having to support a site it has previously rejected absent a persuasive showing on the record that the proffered alternative is both viable and superior. Staff's inability to defend its belated proposal is detailed infra. Even if there is some "lesser standard of proof" required to deny an application, as Staff asserts, the discussion below shows that Staff has not even met that burden.

The Conservation Intervenors acknowledge on brief that Staff has the duty to present evidence supporting its site selection. They concede also that there is insufficient evidence to constitute even a prima facie case for Cape Starichkof. While Staff argues negatively that Gravina Point should not be certificated, Intervenors suggest a "remand" of the siting issue to permit the requisite information and analysis to be included in the record. A remand in the instant case is not supported in law and is contrary to the evidence of record. The Conservation Intervenors have confused a failure to consider an apparently reasonable alternative with a failure to prove that alternative's superiority. The issue is not whether to explore the alternative, but rather how much additional opportunity is required to pursue the alternative once its deficiencies become known and the original proposal is found acceptable. Those cases cited by Intervenors involve situations where an agency, contrary to the dictates of the relevant statutes, either inadequately discussed alternatives in its impact statement or refused to admit evidence on alternatives. Moreover, there was usually no record evidence against the alternative. Thus, an appropriate remedy for the reviewing courts in those cases was to remand. 1/

Such is not the case here. Some 127 pages of the FEIS are devoted to alternatives, with much of that discussion devoted to Cape Starichkof. In addition, there is the gargantuan OIW Report focusing on alternatives in Cook Inlet (ST-37). Staff has had an unfettered opportunity to present evidence in support of its choice. Upon first seeing the Cape Starichkof proposal in the FEIS, the Presiding Judge enumerated on the record the perceived difficulties with any Cook Inlet site, noted that no party had an opportunity to separately evaluate or comment on this "selection" since it was not the Staff's preference in the DEIS, and directed Staff to respond to the obvious deficiencies in its presentation (22,297-22,301). Staff presented its case for Cape Starichkof, including augmenting its position stated in the FEIS, during several hearing days (Vols. 143-145), but was unable to make any showing that its site was even as suitable as Gravina Point, much less superior to it. Indeed, Staff counsel stated he did not intend to present a detailed analysis of Cape Starichkof (21,495). In sum, there has been no failure to consider the Cape Starichkof alternative; rather, Staff has simply been unwilling or unable to support its selection. Thus the remedy is not to remand, but to deny the alternative.

The methodology of the site selections will be considered in Section 2. Analysis of the record evidence ineluctibly leads to the conclusion that the Gravina Point site must be certificated if the El Paso application is approved.

2. Site Selection Process

El Paso selected Gravina Point in western Prince William Sound as its preferred site for the Alaskan liquefaction facilities. This result followed a comprehensive site selection study. After establishing site selection criteria (EP-69), El Paso

1/ The nature of the suggested "remand" remains unclear. During the hearings, Staff was urged to present more detailed evidence to support its proposal, but refused.

determined that the most suitable region was the section of south-central Alaskan coast extending from Prince William Sound to Cook Inlet. The northern segment of Cook Inlet was not included because of severe ice conditions. Within the acceptable region, numerous specific locations were surveyed, resulting in the selection of 13 sites for additional study. The more detailed site-specific findings were plotted against certain evaluation parameters. Each parameter was given a rank of 0-5, with a grade of 0 in any item automatically eliminating the site from further consideration. The results of this evaluation eliminated 8 sites, including Nikiski and Cape Starichkof, which received 0 ratings for oceanographic conditions. Of the remaining sites, Gravina Point was considered the preferred. The State of Alaska and Western LNG have endorsed Gravina Point as the most preferred site.

The Staff commissioned the Oceanographic Institute of Washington (OIW) to do a study of alternative siting in Cook Inlet only. Of 26 sites selected for more detailed study, the OIW concluded that Nikiski was the most preferred site in Cook Inlet, with Cape Starichkof second. Accordingly, Staff recommended, in its Draft Environmental Impact Statement, that Nikiski be the site for the liquefaction facilities. Although Staff terms the OIW report "probably one of the most extensive analyses of an alternative ever made by the Staff" (Initial Staff Brief 3), the recommendation of Nikiski had little staying power. Staff learned that the U.S. Coast Guard considered, on the basis of oceanographic conditions, "the siting of any additional LNG terminals in the Nikiski area a significant hazard to the safety of life, property, and the environment"(ST-38A, letter dated 11/14/75 from Rear Admiral J.B. Hayes to Kenneth F. Plumb).

Forced to reevaluate its site recommendation, in some good part as a result of the Coast Guard's denunciation of Nikiski, Staff analyzed 22 potential sites in Prince William Sound and Cook Inlet. It concluded that Gravina Point was the most acceptable Prince William Sound locale, while Cape Starichkof was now the sole acceptable site in Cook Inlet. While Staff noted that both sites might be suitable locations, it concluded, almost entirely on the basis of its evaluation of biological and socio-economic impact, that Cape Starichkof was preferred. Thus, in the Final Environmental Impact Statement, Cape Starichkof rose like a mushroom from the debris of Staff's initial Cook Inlet proposal. 1/

1/ Commenting on the unfavorable oceanographic information that came to light concerning Nikiski, the FEIS states only that "The Cape Starichkof site apparently lies outside the area of disruption " (ST-19, II-496).

Gravina Point, covering about 1200 acres at the end of the proposed 800-mile trans-Alaska pipeline, presents several environmental concerns of various significance: the 33 miles of pipeline route through the Chugach National Forest; the plant site at the presently unimpacted Gravina Point; the crossing of the proposed wild and scenic Gulkana River; the effect of the pipeline on Comfort Cove; thermal discharge into the Prince William Sound (685,000 gpm of water will be returned to the Sound, an important commercial fishery, at 21°F. above ambient termperature); the possibility that the siting will renew interest in the presently moribund Copper River Highway project; and the impacts on 16 bald eagle nesting sites at Gravina Point, Sitka black-tailed deer near Prince William Sound, Dall sheep in the Brooks and Alaska Ranges and peregrine falcon nesting areas at Franklin Bluffs and Sagwon Bluffs. Some of these impacts might be significant and, in some instances, such as thermal discharge, it is questionable whether there is sufficient knowledge presently available to evaluate the harm. However, Staff concluded that the overall project was acceptable (ST-18, I-A10).

Seismic and glacial considerations related to the Gravina Point site are treated in the El Paso geotechnical section, _infra_, this section. The environmental impact of the LNG plant on Gravina Point is treated in the environmental section, _infra_. 1/

3. Pipeline to Cape Starichkof

There have been numerous difficulties and hazards unveiled on the record concerning Staff's alternative proposal. Staff has not convincingly rebutted these assertions.

Staff has basically relied on El Paso's "Alaskan Gas Pipeline Alternate Route Analyses of All-Alaskan Routes" to justify the feasibility of its alternative route. This report is not in evidence. 2/ As used by Staff, the route would divert from El Paso's proposed route near Livengood (MP 389.5),

1/ Moreover, the State of Alaska, in supporting the Gravina Point site, downgrades the overall significance of the environmental impacts associated with that site selection. Dr. Robert LeResche, Chief, Habitat Protection Section, Alaska Department of Fish and Game, testified that the impact on Gravina Point could be major, but localized. He stated that if construction were to occur as represented by El Paso, the impact of the facility would be aesthetic rather than biological.

2/ Staff chose not to place it in evidence. It is used here only to demonstrate that even on a non-evidentiary basis, Staff cannot support its choice.

extend south to Dunbar, then follow the Multimode Utility Corridor (Alaska Railroad and State Highway 3) to the western shore of the Kenai Peninsula (eastern Cook Inlet). The distance from the diversion point to Cape Starichkof is 422 miles, including a 16-mile crossing of Cook Inlet. The report shows an Atigun/Railbelt/Tyonek to Starichkof route ("B12") rated higher overall than the prime route ("BO") based on estimated capital costs, operations, construction difficulties and accessibility. El Paso has argued that this preliminary report was not intended to and cannot be used to verify the technical feasibility of any pipeline route. The report itself cautions that the "route descriptions are made from information derived from topographic and geologic maps only and are made without a detailed field route reconnaissance." A route reconnaissance would be necessary to describe the conditions more accurately and to determine more precisely where the best routes lie. Unfortunately, the Staff has not undertaken to perform even the low-level reconnaissance recommended by the report. Nor has it performed the essential engineering design work to prove that the difficult problems that confront the proposed route can be overcome. In fact, Staff has carefully warned that its analysis is not intended to be an engineering feasibility study at all, but merely a "route selection."(23,265)

Given this absence of essential technical support evidence and the patent problems of the pipeline route, infra, Staff cannot rely solely on the El Paso Analyses to justify its preference. This report might be enough to "pique Staff's interest," but even if it had risen to an evidentiary status, it is not sufficient to defer certification of Gravina Point.

The proposed route to Cape Starichkof would pass through the rugged Alaska Range. Staff has made no attempt to survey the route through the Range by aerial or ground examination. Instead, it has used a "ruler" approach, whereby a straight-line pipeline route over mountains is hypothesized for lack of more definite route information. Unfortunately, there are serious difficulties involved with a route through the Range, and its feasibility and cost cannot be verified without more extensive onsite studies. A particularly disturbing problem is the possible absence of bedrock necessary to secure anchoring of the pipeline. Staff conceded that it is desirable to have slopes less than 40% on the route, yet placement slopes as steep as 50% are present in the Range. While Staff states that the general presence of bedrock "should assure secure anchoring" on these slopes, there is little evidence supporting either the technical feasibility of this method or the specific presence of bedrock. The fact of the matter is that after reasonable engineering the alignment would be moved, but when, how, where or at what expense are mysteries since studies were not done.

Staff's route also contemplates a 16-mile underwater crossing of Cook Inlet. However, the location of the crossing has not been identified, and Staff has given scant attention to potential problems associated with a crossing. The OIW study (ST-37) does mention that submarine pipelines are typically significantly more expensive to construct and operate. The OIW report concludes that future studies of feasibility of pipeline crossings of Cook Inlet will be required to develop detailed analyses of the ocean environment and state of technology involved. Again, Staff has presented no evidence substantiating the technical feasibility and costs of the crossing. While Staff asserts that there are presently 10 Cook Inlet pipeline crossings, the largest diameter pipeline is 10 inches (23,096). Staff witness, Robert Arvedlund conjectured that the pipeline might have to be buried 15 feet to avoid ice scour, but no study documented the need for or feasibility of a buried crossing. Similarly, Staff did not consider whether ice, currents or wind conditions might hinder maintenance of the line or whether the pipeline should be dualized. (23,264-265)

The intensity of seismic activity along the route is very high. In addition to the Denali fault, the alternative route will also cross the Castle Mt. fault and Eagle River fault. In addition, an aerial crossing of 660 feet will be required over Hurricane Gulch in the Broad Pass Depression.

The environmental impacts of the alternative route are as uncertain as its technical feasibility. The Conservation Intervenors note that the environmental superiority of Cape Starichkof over Gravina Point is not clear and emphasize that little consideration was given to the environmental impacts of the pipeline route. While Staff apparently relies on the fact that the pipeline route will parallel the transportation corridor, the lack of engineering design studies leaves this prospect in doubt. It is clear that the alternative route will cross through the Kenai National Moose Range and pass within 5 miles of Mt. McKinley National Park. It is uncertain whether the route will infringe on the proposed extension of the Park.

Conservation Intervenors add that the route will apparently slice along the eastern edge of the important waterfowl habitat in the Minto Flats and disrupt subsistence homesteads (Conservation Intervenors Brief, 5). Finally the possible environmental damage associated with a crossing of Cook Inlet has neither been studied nor assessed.

4. Cape Starichkof LNG Plant Site

The most significant difficulties in regard to the Cape Starichkof alternative are the meteorological and marine conditions at the LNG plant and terminal site. It was because of anticipated problems in this area that El Paso eliminated both Nikiski and Cape Starichkof from consideration. As stated supra, Staff originally selected Nikiski, on the eastern coast of Cook Inlet 65 miles southwest of Anchorage, as its preferred location. However, the Coast Guard made it clear that severe navigational problems, inter alia, render this site unacceptable. Rear Admiral J.B. Hayes, in his November 14, 1975, letter to Kenneth F. Plumb (ST-38A), warned that tidal currents at Nikiski, reinforced by wind-driven currents, complicate navigation and docking. In conjunction with these tides and currents, winter ice presents major problems. Forming between November and April and ranging up to 0.5 mile in width and 5 feet thick, the ice cakes may move at near surface current velocities. The most substantial danger is that of a large cake of ice or a buildup of smaller cakes forming between the marine terminal and the ship and exerting pressure on the mooring lines. The ship must then cast off or risk rupture of the lines. The navigational hazard is that the large "pans" of ice must be avoided. Unfortunately, numerous ice-related navigational and berthing incidents have occurred at Nikiski (ST-19, II-490; ST-37, 4-58). El Paso witness Robert McCollum testified that during the first 4 months of 1972, 6% of the traffic coming into Cook Inlet was damaged by ice. Finally, "slush ice" can be formed and drawn into the intakes of ships. On several occasions, actual power failures on ships have resulted.

The OIW study (ST-37) concedes that sea ice in conjunction with extreme tidal currents creates serious problems for navigation, docking and loading of vessels. The report still recommended Nikiski as its prime site, evidently overlooking the effect of the increased LNG vessel traffic that would be using the port, and the importance of strict scheduling for the El Paso project.

It is unclear whether dredging would be needed at Cape Starichkof. Staff assumes neither initial nor maintenance dredging would be necessary for the marine terminal. It is conceded that dredging would be costly and possibly environmentally unacceptable, adversely affecting the shellfish in the area. (23,222-223) Staff seems to base its optimism on a Corps of Engineers' opinion that no dredging should be required as long as the approach structure is open and does not interrupt natural littoral transport along the shore (ST-31C). However, Staff acknowledges that it does not know whether the pier can be constructed so as not to interrupt the littoral transport. (23,226) In fact, both the FEIS and OIW report state that sediment movements would create the need for repeated maintenance dredging. In addition, no surveys have been performed of bottom profiles and soil conditions, and there is thus insufficient data to design the wharf support structure.

A similar problem exists in regard to the site geology. While Staff is aware that major facilities of the LNG plant would need to be founded on bedrock, the location of bedrock on the site is unknown. Staff does know that there are no bedrock outcroppings at Cape Starichkof, and there is no bedrock in the top 60-feet (23,211-215),

As is true of the pipeline route, the environmental superiority of the Cape Starichkof site has not been proven. Cape Starichkof remains a relatively undisturbed area, despite the presence of 7 residences and a radio tower. Moreover, the LNG plant would lie within 1 or 2 miles of the mouth of the Stariski Creek, which supports substantial runs of chinook and coho salmon and steelhead trout. The creek receives considerable attention from recreational fishermen. In addition, a major commercial salmon fishery is located nearby, and beds of razor and red-necked clams are found offshore. There are also dense winter concentrations of moose at Stariski Creek, some of which might congregate at the site. As mentioned earlier, the Cook Inlet crossing and offshore dredging remain uncertain environmental hazards. 1/

1/ It is also significant to note that the Cape Starichkof site will necessitate an LNG fleet trade route which is 170 miles longer than Gravina Point. Staff has not assessed the impact of this on El Paso's fleet schedule. Rather, Staff has conjectured that an increased ship speed and the use of the 20-day down time projected by El Paso can compensate for the longer route (23,169). However, it is difficult to see how the down time can be used, since it is intended to cover the yearly maintenance of the LNG plant. See infra.

Staff has been unable to show adequately that marine and meteorological conditions at Cape Starichkof, 60 miles south of Nikiski, are acceptable. El Paso set 2.0 knots as its current velocity criterion, yet the currents at Cape Starichkof average 2.2 knots, almost twice as great as at Nikiski. (The diurnal tidal range is 19.1 feet, which is greater than Nikiski and contributes to high current velocities.) There is no wave, wind velocity or visibility data site-specific to Cape Starichkof. Most importantly, Staff has assumed that "The Cape Starichkof site apparently lies outside the area of (ice) disruption " (ST-19), II-496). However, in response to a Staff inquiry, Rear Admiral Hayes stated (ST-31B: letter dated 2/4/76 from Rear Admiral Hayes to Kenneth F. Plumb):

> While ice conditions are probably less severe (than Nikiski), both as regards the amount of ice and the duration of the ice season, there is ...insufficient date from which to formulate answers to your questions regarding shipping safety, time delays, etc. Again I can only urge that members of your Staff visit Cape Starichkof during the winter season before any decision is made.

Staff considered the Corps of Engineers more optimistic. The Corps indicated that, while there is no data on icing in Cook Inlet, subjective observations indicate surface coverage by ice should not exceed 20% at Cape Starichkof. (ST-31C: letter dated 2/24/76 from Charles Debelius to Kenneth F. Plumb) Finally, while the OIW report (ST-37) indicates that Cape Starichkof is normally ice-free, the report shows that sea ice has appeared in southern Cook Inlet in severe winters (e.g. 1970-1971). Moreover, of the 16 ice-related accidents reported by OIW in Cook Inlet ("Ice Casualty Incidents, Cook Inlet, 1971-1974," ST-37, 4-58), 2 occurred west of Cape Starichkof, 2 near Ninilchik just north of the site, and 1 in Kachemak Bay southeast of the Cape. In answer to the OIW assertion that these accidents occurred to older vessels not designed to withstand ice conditions, it should be noted that the FEIS lists numerous ice-related incidents affecting LNG ships at Nikiski. (ST-19, II-490) Staff has not presented sufficient evidence to support the acceptability of Cape Starichkof from the standpoint of navigational and berthing safety and susceptibility to delays. An additional factor to be considered is the proposed 4060-foot pier which would be vulnerable to ice pan collisions. So far, Staff has not analyzed effects of ice loads on the pier (23,153).

5. Conclusion

No extended discussion is necessary in summation. The choice of Gravina Point is supported by substantial evidence of record and Cape Starichkof is not. On the basis of the evidence of record, and giving the best gloss to that evidence supporting Staff's proposal, Cape Starichkof cannot be found to be a reasonable or viable alternative. If El Paso is certificated, its LNG plant should be located at Gravina Point.

One final observation must be made here. A denial of El Paso Alaska's application in this proceeding for a Prince William Sound terminal would not necessarily mean that El Paso will never construct a liquefaction plant in the Gravina Point area. It is generally recognized that the Gulf of Alaska is one of the nation's most promising frontier provinces for future oil and gas discovery. An initial substantial sale of leases to producers was made by the Department of the Interior in early 1976 for the near-shore area between Kayak Island and Icy Bay, a region roughly 100 to 150 miles from Gravina Point.

H. El Paso-West-Coast Siting

Western LNG Terminal Company (WLNG), as part of the El Paso Alaska project, has proposed to site its regasification plant at Point Conception, California, located 120 land miles northwest of Los Angeles, California. The Staff, Conservation Intervenors, and the State of California argue that Oxnard, California, a site just south of Los Angeles (60 land miles and 70 sea miles southeast of Point Conception) is the preferable location.

While the record will support a finding that both sites are acceptable, the weight of the evidence is that Oxnard should be certificated as the site to receive the natural gas transported from the North Slope of Alaska by El Paso. Given this finding, it is unnecessary to decide at this time which sites should be certificated on the west coast for the additional LNG projects presently being proposed. 1/

1. Site Proposal

Before analyzing the two sites being compared, an examination of the site-selection process is important. WLNG evaluated seven "feasible" sites on the west coast and eventually offered three "preferred" sites to El Paso: Point Conception, Oxnard, and Los Angeles. WLNG has consistently refused to state on this record which site it deems preferable as a location for an LNG project, maintaining steadfastly that all three sites are equally acceptable. WLNG, in fact, actually chose Los Angeles and Oxnard as suitable locations prior to selecting Point Conception 2/ and firm commitments had been entered for both even before WLNG entered into negotiations with El Paso.

Staff analyzed ten sites: Los Angeles, Oxnard, Point Conception, Port Hueneme, Carlsbad, Border Field, El Segundo (WLNG's seven "feasible" sites), Drake, Mandalay and San Onofre. Los Angeles and 4 other sites were rejected after initial analysis. 3/

1/ Proposals are presently before the Commission to construct California regasification facilities to receive LNG from Indonesia (Pacific Indonesia LNG Company, et al., Docket Nos. CP74-160 et al.) and from the Kenai Peninsula in Alaska, (Pacific Alaska LNG Company, Docket No. CP75-140).

2/ WLNG witness K.C. McKinney testified that his company identified Los Angeles harbor in 1965 for the Pacific Alaska project and next considered Oxnard for the Pacific Indonesia project 153/25,274-276).

3/ Los Angeles was rejected because of seismic risk and by stipulation of all parties is not proposed as a viable alternative in the instant case 143/23,128).

The remaining sites were subjected to an in-depth analysis, after which Oxnard was chosen as the preferred site. Staff has also engaged the Intersea Research Corporation to undertake an independent site-selection study, Intersea initially analyzed 47 sites, eventually choosing 7 sites for detailed study. Their weighted results, of the sites chosen for detailed study, rank San Onofre as the preferred site, Oxnard second, and Point Conception tied for sixth and last.

In its initial filing, WLNG proposed Point Conception to receive a 2.8-Bcf/d average with a 3.1-Bcf/d maximum load. In its latest filing, a 2.1-Bcf/d average, 2.4-Bcf/d maximum load was proposed. The terminal facility, as proposed, would occupy 101 acres of a 227-acre site and would consist of two ship berths, four 550,000-bbl storage tanks, 2 transfer lines, 28 seawater vaporizer units, 3 gas-fired vaporizer units, and a 4,600-foot long trestle. WLNG also proposed a twin 42-inch diameter pipeline from Point Conception to a point west of Arvin (90 miles), single 42-inch diameter pipeline from this point to MP 133 (43 miles), a single 42-inch diameter pipeline from MP 133 to Arvin (9 miles), and a single 42-inch diameter pipeline from MP 133 through Adelanto to Cajon (108.6 miles). The total distance covered is 250.6 miles, and the actual length of new pipeline is 340.6 miles. Throughout this system, gas would be delivered to existing pipelines which would transport it both to California markets and to the California-Arizona border.

While no specific study has documented the facilities necessary if Oxnard is certificated to receive the El Paso North Slope gas, it is apparent that the 210-acre Oxnard site will be able to accommodate the facilities necessary for the Alaskan volumes. WLNG, in fact, studied a hypothetical 3-Bcf/d average, 4.2-Bcf/d maximum load plant at Oxnard. 1/ In Case #7 of WL-50 facilities listed for this plant include 2 berths, 2 transfer lines, four 550,000-bbl storage tanks, 30 seawater vaporizer units, 12 gas-fired vaporizer units, and a 5,850-foot long trestle. These are approximately the same facilities as proposed for Point Conception.

There has also been no detailed study within the four corners of this case analyzing the transportation of the specific North Slope volumes of gas from Oxnard. However, the DOI FEIS "Alternatives" volume specifies a 157-mile long pipeline route (actual

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1/ This theoretical facility would receive gas from all three projects.

new pipeline - 169 miles) from Oxnard, through Quigley Station, to Hinkley for a 3-Bcf/d peak capacity of North Slope gas. Intersea Research Corporation studied a 53.3-mile long route from Oxnard through La Vista and Saugus to Quigley Station, which is similar to the "ultimate development" route suggested by Staff in Pacific Indonesia LNG Company, et al. to transport 4 Bcf/d of gas (ST-20, III 339-343) 1/.

Whatever pipeline emanating from Oxnard is ultimately certificated, it is clear that it will provide a technically feasible means of moving gas from the coast through the market areas in California and east to the California-Arizona border. In fact, a pipeline system starting at Oxnard would be much shorter than one carrying the same amount of gas, serving the same markets and starting at Point Conception. As WL-50 demonstrates a single terminal at Point Conception receiving 3.0-Bcf/d average load from all three projects would require 492.2 miles of pipeline over 250.6 miles (Case #6). Yet a single terminal

2. Environmental and Technical Considerations

a. Seawater Exchange

WLNG intends to use seawater vaporizer units to gasify the average load of LNG. At the Point Conception site, seawater will be taken from the ocean, used as a heating agent, and returned to the sea at a temperature 12°F. below the ambient water temperature. At 2.8-Bcf/d average, 300,000 gpm of cooled water will be discharged.

WLNG has conceded that the effects of the discharge on marine biota are uncertain. While WLNG hopes that diffusers will mitigate the problem to some extent, no studies on the biological effects of the cooled seawater discharge are presently available. Moreover, specific impact assessment is impossible because the design and location of the outfall has yet to be determined. At the very least, it appears that certain warm water species may not be able to survive the decreased water temperatures. Other species will suffer sublethal effects, including changes in growth rate, size and reproductive periods. In addition, mortality of some species is almost certain to occur by entrainment in the intake line. Finally, biocides such as acrolein will be added to the intake water to inhibit fouling by marine animals. If accidentally spilled, the substance could enter the marine system and kill organisms in the area.

At Oxnard, seawater can be provided by Southern California Edison's oil-and gas-fired Ormond Beach Generating Station, located adjacent to the site. This twin-generator plant will be capable of supplying sufficient heated seawater to meet the LNG plant's vaporization needs. If the power plant discharges insufficient waste heat or is shutdown, seawater heaters can be used to prevent subambient discharges. Moreover, gas-fired vaporizers can be used for maximum loads or when the seawater vaporization system requires maintenance. The existing power plant intake and discharge structures would not require modification for use at the LNG plant. The seawater will be discharged through existing power plant discharge lines. By using the power plant seawater discharge for vaporization, the Oxnard LNG site would avoid the potential impacts of cooled discharge, entrainment, and biocide spill. Moreover, by lowering the power plant discharge temperature, any potential impacts from heated discharge would be mitigated. 1/

1/ ST-49 and ST-50, which bear on the ability of the seawater exchange system to withstand seismic events, are hereby admitted into evidence.

b. Land Use and Socio-Economics

It is beyond dispute that an Oxnard plant site would be more consistent with the present and future land uses of the site area than a facility at Point Conception.

The proposed Oxnard terminal is situated in the Ormond Beach Industrial Area, zoned for long-range heavy industrial use. Several industrial facilities are in the immediate vicinity of the plant site. The proposed Point Conception site, adjacent to the ocean and the Santa Ynez Mountains is a picturesque area with no industrial development and little urban use. The area is essentially rural, zoned for limited agriculture and currently used for cattle grazing. Adjacent to the site is the Hollister Ranch, consisting of 130 sizable parcels of exclusive residential land presently being sold and developed. WL-14 conceded that the aesthetic impact would be greater at Point Conception than Oxnard, and there is no serious argument that an LNG facility at Oxnard is more consistent with the present and planned future development of the area. No comparisons on this issue favor Point Conception.

Neither site development would present significant long-term socio-economic problems for the areas, since the maintenance and operations crews will be small. However, whatever housing and government services burdens are imposed during the construction stage would be more severely felt in Point Conception. The Oxnard site, located near several urban areas, can take advantage of the labor force, housing supply, and government services that these areas can provide. Especially in the area of available housing, the Point Conception community would have more difficulty accommodating the influx of construction workers.

c. Biota

Other than the beneficial effect of power plant or change at Oxnard, supra, there are no significant differences in impact on biota from the LNG terminals at the two sites. However, the greater length of the Point Conception pipeline and the larger degree of habitat disturbance associated with the pipeline construction will inevitably lead to greater adverse impacts on biota. The proposed pipeline from Oxnard to Quigley Station follows existing rights-of-way for 96% of the route, while the line from Point Conception to Arvin follows existing rights-of-way for 9% of the route (ST-20, III-351). WL-14 conceded that Point Conception would have the most detrimental effect on wildlife habitat and species disruption because of the length of the pipeline and terrain crossed.

The main impact on wildlife will stem from habitat and food source disruption. The Point Conception-to-Cajon route will require 3,400 acres of right-of-way, substantially more than the Oxnard-to-Quigley Station line. Loss of habitat is most harmful in areas where a particular habitat for a certain species is extremely limited, such as woodland areas. There are 215 acres of woodland on the proposed route. 1/

The Point Conception route could also have impacts on four endangered, rare and protected species of animals: construction passes through 47 miles of habitat of the San Joaquin kit fox; construction could have impacts on prairie falcon nesting; construction passes near populations of the blunt-nosed leopard lizard; and a portion of the route from Arvin to Cajon crosses a California condor habitat.

The impacts on vegetation are also predicated basically on the lengths of the pipeline routes. The acreage cleared for the rights-of-way will be reseeded and ideally will undergo ecological succession. However, oak and juniper woodlands may take 100 years to reach climax stage. In addition, the desert communities traversed by the Point Conception route are fragile and might take up to 300 years to reach climax. Some species here might take even longer to return to their preconstruction state. (The Oxnard-Hinkley alternative also passes through the Mojave Desert.) Finally, 15 miles of the Point Conception route will traverse the Los Padres National Forest, an impact not found on the preferred route

The most significant factor which would deter successful revegetation is erosion: Both routes have high water erosion potential and the Point Conception route would also experience wind erosion in the desert. Along 50% of the pipeline route from Point Conception to Arvin, ridge-cutting will occur. In addition to possible contour failure, the spoil dirt will bury some vegetation, and the ridge-cut slopes would be scarred where the excavated material pushed over the sides was deepest. These newly created slopes may not be stabilized quickly by natural vegetation, and even with revegetation, some erosion would likely occur.

1/ No reliance has been placed on the FPC DEIS in Pacific Indonesia LNG Company, et al., since this document is not of record in this proceeding. However, alleged facts contained in that DEIS, if weighed, would serve to corroborate the conclusions in this regard. For example, it is revealed that only 729 miles of right-of-way is required for the Oxnard-to-Quigley Station route, only 72 acres of woodland will be traversed, and only 2.5 miles of ridge-cutting will be necessary.

Topographically, the Oxnard site area is essentially level and will require minimum grading. At the Point Conception terminal site, two million cubic yards of material will be moved for grading purposes, and two arroyos which drain part of the southern part of the site will be filled. There are some allegations that the eastern slope of the Canada del Cojo, a biologically significant canyon, will be altered, although WLNG has stated that this area will not be disturbed.

d. Archaeology

The Point Conception terminal site and pipeline route would have a significantly greater impact on archaeological sites than the Oxnard facilities. There are believed to be at least two significant Chumash village archaeological sites within the boundaries of the Point Conception LNG facility. WL-14 conceded that one or more of these suspected sites will probably soon be registered. A total of 27 sites are known for the entire Point Conception area, and 12 are in areas of high probable impact. There are also clusters of 40 known sites along the pipeline route, including the Cajon Quadrangle at the end of the route, containing 23 formally recorded sites. Several of these sites have recently been nominated to the National Register.

e. Seismicity

Although the critical facilities at each site are designed to withstand the maximum credible earthquake expected, it is still important to examine the relative seismic hazards of each area. Many support facilities will not be designed by these applicants (e.g. power plants); others will not be designed to withstand the maximum credible earthquake (e.g. LNG transfer lines). Outages for testing and inspection might be required even if the facility withstands a seismic event, and the design itself might simply be inadequate. The conclusion reached is that Oxnard has a small advantage over Point Conception.

Neither site has a fault within its boundaries, and earthquake displacement is not a significant danger at either location. The nearest fault to the Point Conception site is the Santa Ynez fault, 3 miles from the site. The FEIS of the FPC states that the maximum expected event from this fault would result in a 7.0 to 7.6 magnitude earthquake with a maximum bedrock acceleration of 0.7g. 1/ On brief, Staff states that the smallest value

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1/ WL-14 stated that the maximum bedrock acceleration would be around 0.25g. This level is reaffirmed on brief (Western LNG Initial Geot. Brief, 3).

it can justify at Point Conception for bedrock acceleration is 0.6g (Staff Reply Geot. Brief, 12). On the other hand, the FEIS reports that the maximum expected magnitude from the Hueneme Canyon fault, 2 miles offshore from the Oxnard site, is 6.0 to 6.8 (ST-20, III-363).

The Science Applications Inc. (SAI) studies offer the best indication of bedrock acceleration. WL-51 gives the expected peak accelerations in rock as a function of recurrence intervals for a 200-km. sq. area around the Oxnard site:

0.2g -	45 yrs.	.75g -	5.2×10^{5} yrs.
0.3g -	350 yrs.	1.0g -	1.9×10^{7} yrs.
0.4g -	2,000 yrs.	1.5g -	9.6×10^{9} yrs.
0.5g -	11,500 yrs.	2.0g -	1.0×10^{12} yrs.

With a design g-level for tanks of 0.32g, the study gives the probability exceeding this as 1.0×10^{-17}/year. WL-53 gives the expected peak accelerations in rock at the Point Conception site:

0.2g -	59 yrs.	.75g -	2.0×10^{5}
0.3g -	370 yrs.	1.0g -	2.1×10^{6}
0.4g -	1,700 yrs.	1.5g -	3.6×10^{8}
0.5g -	6,500 yrs.	2.0g -	3.8×10^{10}

Using a design g-level for tanks of 0.32g, the probability of exceeding this is 1.1×10^{-5}/year. 1/

It was conceded by WLNG witness K.C. McKinney that the Point Conception-to-Cajon route encounters more areas of seismic risk than the Oxnard-to-Quigley Station route (153/25,105). The former route crosses 25 fault traces, many of which present displacement hazards to the pipeline. Bedrock accelerations of 0.7g could also be experienced. 2/

1/ The Point Conception probability figure is conservative, however, because here, unlike Oxnard, the lack of soil samples forced the researchers to assume that the bedrock acceleration equals surface acceleration (i.e., no attenuation is assumed). On the other hand, the study assumed a g-level design of 0.32g, while the applicants have proposed a 0.25g-level design for Point Conception.

2/ The FPC DEIS in Pacific Indonesia LNG Company, et al., alleges that the route from Oxnard to Quigley Station crosses 10 fault traces and is within 2 miles of 7 others. Ground shaking could reach 0.7g, and three faults are capable of causing up to 2 feet of displacement.

f. Utility Use

Since the Oxnard terminal site is closer to a large urban area, it has a more accessible supply of electricity and water than Point Conception.

At Point Conception, the electric power requirements of the LNG plant would require substation expansion and the addition of a 35-mile long transmission line. The cost of the new facilities is estimated at between $3 million and $5 million. WLNG has not yet specified its source of fresh water supply. It is considering onsite wells if there is sufficient usable water on the site. The only alternative is a new water pipeline. 1/

3. Risk

The major safety consideration associated with the transport, storage and vaporization of LNG is concerned with large, unconfined spills of the fluid. When LNG is spilled on a relatively warm surface, like earth or water, it boils, vaporizes and achieves a positive buoyancy at temperatures above -148°F. The vapor cloud mixes with the air is flammable if the vapor content is between 5% and 15% by volume of the mixture. If such a mixture should reach a source of ignition (e.g., auto sparks, lit cigarette), there will be a fire at that point which will travel back through the vapor cloud to the source and will start a fire over the liquid spill. See LNG safety discussion, supra.

Several studies submitted by Staff and WLNG have been admitted in this case concerning the risk of fatality from LNG spills and subsequent vapor fires over populated areas. All the studies concluded that the risk is acceptable at the Oxnard site, and no party has disputed this fact. 2/ The SAI study, a conservative document offered by WLNG, analyzes risks from all possible initiating sources. It concludes that, at a throughput of 4 Bcf/d, the maximum risk level at Oxnard is one in 6.7 million per person per year within five-eighths mile of the site, decreasing to one in 10 million per person per year or less within

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1/ The FPC DEIS in Pacific Indonesia LNG Company et al., alleges that only a 1.5-mile long transmission line need be built for the Oxnard facility, and the City of Oxnard will probably be able to supply fresh water to the site through an existing water main.

2/ Staff termed the Los Angeles risk marginal, and both Staff and SAI found Point Conception to be less risky than Oxnard.

1 mile of the site. Beyond 3 miles, the risk is less than one in 10 billion. The probability of one occurrence of 2,000 to 10,000 fatalities is one chance in 100 million per year. Since the probability of an electric shock fatality in an electric-wired residence is one chance in one million per person per year, the fatality probability within five-eighths mile of the site because of LNG spills is 15% that of electric customers.

The State of California recently enacted the California Coastal Act (Senate Bill 1277, signed by Governor Brown on September 30, 1976). A portion of this legislation provides.

> Until the risks inherent in liquefied natural gas terminal operations can be sufficiently identified and overcome and such terminals are found to be consistent with the health and safety of nearby human populations, terminals shall be built only at sites remote from human population concentrations. Other unrelated development in the vicinity of a liquefied natural gas terminal site which is remote from human population concentrations shall be prohibited. At such time as liquefied natural gas marine terminal operations are found consistent with public safety, terminal sites only in developed or industrialized port areas may be approved (California Public Resources Code, Section 30261(b)).

The State of California has indicated, on brief, that it "does not believe that the above-quoted language ... prevents Oxnard from being chosen as the site for the first regasification facility in California" (California Reply Siting Brief, 3). 1/ The intent of the Act is seemingly to forestall LNG plant construction in both densely populated areas and in pristine areas considered by California to be worthy of preservation.

1/ This is not intended to portray the views of the California Coastal Zone Conservation Commission. In its Position Brief, the State of California, (i.e. "The People of the State of California and the Public Utilities Commission of the State of California") reaffirms its support for an Oxnard siting, as stated in its California Siting Brief. However, California felt compelled to append to its Position Brief the opinions of two state agencies which have disagreed with its site preference. Appendix A states the views of the State Energy Resources Conservation and Development Commission, which contends that the CPUC acted prematurely in endorsing Oxnard as the preferable site. Appendix B states the views of the California Coastal Zone Conservation Commission, which contends that only it has the authority to make findings concerning LNG plant siting. It should be noted that neither of these state agencies presented their views on the record in this case.

Oxnard falls in neither of these categories. It is an industrialized port area with low population and risk levels. 10/ Assuming, for example, the simultaneous rupture of two ship tanks without simultaneous ignition (extremely unlikely), the maximum downwind distance the vapor plume would travel is 2.35 Km. In that the proposed pier will be 1.79 Km long, the maximum plume will only travel 0.56 Km on land. If only one tank ruptures, the plume would not reach land before dispersion. One must also assume the accident occurs to a fully loaded ship at berth and that the collision occurs with enough velocity to rupture both the inner and outer hulls without causing immediate ignition from the friction (145/23,416-422). Finally, the wind must be absolutely malevolent in speed and direction. See also discussion on LNG safety supra.

10/ Population Data Used in Oxnard Study
(1990 Projections)(WL-51, Table 8.2.1)

Radius About Site (Km)	Total Population	Dominant Population Characteristics
0-1	1,897	Industrial[a]
1-2	13,987	Residential/Commercial
2-3	20,157	Residential/Commercial
3-4	22,248	Residential/Commercial
4-5	23,810	Residential/Commercial
5-6	27,803	Residential/Commercial
6-7	21,808	Residential/Commercial
7-8	23,374	Residential/Commercial

[a] Estimated Nighttime Population

4-12 P.M. - 190 12 P.M. - 8 A.M. - 95

4. Conclusions

All of the evidence points to Oxnard as the preferred location for an LNG regasification facility. Regardless of the argument whether there is a benefit to spreading the risk through multiple smaller facilities, almost all points of comparison between Oxnard and Point Conception are unfavorable to Point Conception--present and future land-use, environment and projected overall costs (even though assumed in some measure for Oxnard). It is noted that the additional ship found necessary to lift the LNG for El Paso's 2.4Bcfd case is required on the grounds of reliability whether Oxnard or Point Conception is chosen as the site for the LNG regasification facility. While no finding is made that Point Conception is unacceptable, Staff has met its burden of showing that the Oxnard alternative site is more suitable. See Burden of Proof for Alternative Discussion, Section G, *supra*. If the El Paso project is certificated, WLNG's license should be conditioned upon submission of an application to construct an LNG regasification plant capable of the 2.4Bcfd of North Slope gas at Oxnard.

I. El Paso - Cryogenic Tanker Fleet

Unlike the foregoing engineering and geotechnical analysis of El Paso's project (e.g., seismic, soil, or liquefaction plant design) in which it is impossible to fully quantify the additional work necessary to complete the project after certification, the cryogenic tanker fleet lends itself to more definitive analysis. Apart from possible cost overruns in ship construction, upon which Arctic Gas' witness DeLeon effectively put a 10% ceiling (156/25,848-25,856), the number of ships needed to transport (lift) the LNG produced at Gravina Point constitutes a discrete project component with readily identifiable parameters and cost consequences. El Paso, in its application and through its witnesses, presented evidence on the operations of the cryogenic fleet. In addition, Arctic Gas questioned El Paso's witnesses on the assumptions made in using 8 or 11 ships, respectively, for the 2.4 Bcf/d or 3.2 Bcf/d alternative cases, and the record provides adequate evidence to test the reasonableness of El Paso's fleet size. Sections 1-6 below analyze El Paso's 2.4 Bcf/d, eight-ship case without any computer modeling. On a best-case basis without a change in terminal siting, at 2.4 Bcf/d throughput it is found that El Paso needs at least one additional ship. If anything less than 2.4 Bcf/d throughput occurs, the eight-ship fleet design becomes more conservative, but the cost per Mcf rises.

El Paso considers that its own computer model for ships is proprietary (e.g., 51/7650-7651) and, while that model was offered for in camera use, the offer was not accepted because fairness, if not due process, requires access by all parties to any computer assistance employed by the Presiding Judge. Since El Paso's model was not "available," a computer simulation model was developed which will be available to any party for scrutiny. Section 7 consists of the output of that model and the basis upon which it was developed. 1/

1. General Analysis

Under the 2.4-Bcf/d case, El Paso would employ eight cryogenic tankers, each having a capacity of 165,000 cubic meters. 2/ The record shows that El Paso arrived at eight ships as follows

1/ Presumably this model will be made available by the Commission to any person upon reasonable terms and conditions as set by the Commission.

2/ According to El Paso's witnesses Schmitt, each tanker will cost $150,700,000 (July 1, 1975, dollars) to construct (94/14,505).

(Section 5 of Volume II of El Paso's certificate application (EP-73) and further testimony of witness Schmitt (94/14,511-14,515):

Tanker capacity	165,000 m^3
Annual ship utilization time	330 days
Drydock schedule	
Drydock time	14 days
Voyage to yard and gas free	2 days
Return to service and cool down	4 days
Total drydock	20 days
Random repair and delay	15 days
Total out-of-service time	35 days
Mileage	
Gravina Point to Point Conception	1,902 nautical miles
Roundtrip	3,804 nautical miles
Average service speed	18.5 knots
Within 6 miles of Gravina	14 knots
Within 10 miles of Point Conception	10 knots
LNG plant production loaded annually	907,328,000 MMBtu/year
LNG delivered annually	891,903,000 MMBtu/year
Heel and boil-off annually	15,425,000 MMBtu/year
Annual shiploads	232
LNG production loaded daily (1,157.8 Btu/cf)	2,147.03 MMcf/d
LNG delivered daily (1,160.2 Btu/cf)	2,106.16 MMcf/d
Heel and boil-off	1.9%
Gas/LNG volume ratio	593/1

Time in port		
Gravina		
Tie-in time		
Pick up pilot	1.5 hours	
Delay in pilotage water	1.0 hour	
Mooring	1.5 hours	
Connecting lines	2.0 hours	
Average total		6.0 hours
Average pumping time		14.6 "
Cast-off time		
Disconnect lines	2.0 hours	
Cast off	1.5 hours	
Delay in pilotage waters	1.0 hour	
Drop pilot	1.0 hour	
Average total		5.5 "
Total average time at Gravina		26.1 "

Point Conception

Tie-in time		
Pick up pilot	0.5 hour	
Delay in pilotage water	1.0 hour	
Mooring	1.5 hours	
Connecting lines	2.0 hours	
Average total		5.0 hours
Average pumping time		14.6 "
Cast-off time		
Disconnect lines	2.0 hours	
Cast off	1.5 hours	
Delay in pilotage waters	1.0 hour	
Drop pilot	0.5 hour	
Average total		5.0 "
Total average time at Point Conception		24.6 hours

As discussed more fully herein, El Paso projects that each tanker will use an 11.5-day actual round trip, computed at 10.72 days for the round trip and 0.8 days per trip for contingencies. An additional 15 days per year is provided for random repairs and delays--presumably mechanical. Finally, El Paso allows 20 days per year drydock time for each tanker. 1/

2. El Paso's Best Case

Assuming, arguendo, that all of these port and transit factors relied upon by El Paso are correct, it is barely possible that El Paso could eke out its energy transportation system with eight cryogenic tankers. As will be indicated below, the tanker fleet of eight ships may have some limited flexibility if less than 2.4-Bcf/d throughput occurs. But, in the full 2.4-Bcf/d case upon which El Paso's unit costs are computed, the eight-ship fleet is inadequate and will allow no flexibility. Admittedly, this analysis is static and is presumed to be much less sophisticated than El Paso's simulation model. It nonetheless demonstrates the inadequacy of the eight ship fleet if flexibility and reliability are ingredients in determining where the public interest lies.

1/ Periodic drydocking of each of the tankers is important to fleet efficiency and reliability. Indefinite postponement of drydocking of seven ships in order to compensate for the loss of one ship for a period exceeding 2 or 3 years would appear imprudent.

At the outset, the 11.5-day round trip is possible, if the 0.8-day (19.2 hours per trip) contingency time is reasonable. El Paso has allowed 10.72 days for the round trip, absent contingencies:

26.1	hours	time in port at Gravina
24.6	hours	time in port at Point Conception
101.9	hours	1,886-nautical mile one-way trip
101.9	hours	1,886-nautical mile one-way trip
0.42	hour	6 miles into Gravina at 14 knots
0.42	hour	6 miles out of Gravina at 14 knots
1.0	hour	10 miles into Point Conception at 10 knots
1.0	hour	10 miles out of Point Conception at 10 knots
257.3	hours	= 10.72 days

El Paso has argued that its ship scheduling is conservative and that all such contingencies as port closure because of weather, operating limitations for Prince William Sound and the Santa Barbara Channel imposed by the Coast Guard, and loss of time due to weather at sea are included. In addition, El Paso has alloted 15 days for random repairs and delays. The assumption in this section is that all contingencies and delays do not aggregate more than 35.8 days per ship (0.8 x 26 trips = 20.8 + 15) and that the delays are spread out over the year in order not to disproportionately affect ship scheduling in any one season. The main thrust of this analysis is to determine whether the eight ships making the 11.5-day trip can physically move the LNG. It is found that it is conceivable for this eight-ship fleet to lift the 907,328,000 MMBtu/year proposed by El Paso and that, at the given Btu content of 1,157.8 Btu/cf, this annual volume to be lifted equates to 783,665 MMcf, or 2,147.03 MMcf/d.

Each tanker has a capacity of 165,000 cubic meters, or 5,826,925 cubic feet of LNG, which by the use of the 593/1 gas/LNG ratio is a gas capacity of 3,455.3 MMcf per ship. Ignoring heel requirements, the assumed 232 shiploads could lift a maximum of 801,629 MMcf/year, thereby providing capacity flexibility of around 2% at a full throughput of the 2.4 Bcf/d.

The net capacity of each tanker is not, however, 165,000 cubic meters. To begin with, the capacity must be reduced 2% to account for the Coast Guard regulation that LNG tankers be loaded only up to 98% of capacity (51/7685). The resulting net capacity per ship is therefore 161,700 cubic meters, or 3386.2 MMcf of gas equivalent.

In addition, heel must be taken into account. Heel is the amount of LNG which must be retained in the tanker after delivery to permit additional LNG loading without further cool-down. Unfortunately, the record evidence on this point (52/7796-7801) is inconclusive. In Distrigas Corporation, 47 FPC 797, 808 (initial decision issued June 14, 1971), a 1% heel for the cryogenic tanker "Descartes" was designed. Since the heel required is in part a function of the ballast return trip time, the heel needed for El Paso's tankers in this situation could well be less.

In its fleet simulation, El Paso used a heel of around 353 cubic meters of LNG per ship returning to Gravina (52/7770), or-about 0.2% of ship's capacity; however, El Paso warns against using this figure in ascertaining the material balance (52/7797). In fact, El Paso's tanker witness Schmitt states that the ships return to Gravina with sufficient heel to avoid a cool-down delay (52/7797-7799). He also stated that the difference between LNG loaded at Gravina and delivered at Point Conception (15,425, 000 MMBtu/year in the 2.4 case) includes boil-off for the entire 11.5-day round trip (52/7799-7800). However, he never resolved whether the heel was what remained after this boil-off. He concluded that the heel at Point Conception was equal to the 4.32-day ballast return trip, plus an additional 1.5-day delay allowance, times the 0.15% boil-off factor (52/7801).

Pursuant to this formula, El Paso would presumably leave initial heel at 0.87% of net capacity or 1,407 cubic meters in each tanker for the return trip from Point Conception to Gravina. Assuming no delay, each tanker would arrive at Gravina with 363 cubic meters of residual heel, which would have to be deducted from the tankers' net capacity. For the gross calculations performed herein, this is remarkably close to the aforementioned 353 cubic meters. The resulting 0.2% residual heel is corroborated by subtracting 1.7% total round-trip boil-off (11.5 days times 0.15% per day) from the 1.9% heel and boil-off figure previously calculated (2,147 MMcf/d to 2,106 MMcf/d).

Although it is quite possible that El Paso would have to provide for more than 0.2% residual heel at Gravina, the present record confines the heel to this 0.2%. Net capacity is therefore reduced to 161,337 cubic meters of LNG, or 3378.5 MMcf gas equivalent. Giving El Paso its claimed 232 shiploads for the moment, the eight-ship fleet could only lift 783,812 MMcf of gas per year, which is only slightly more than the projected annual gas volume of 783,665 MMcf.

There is some question, however, as to whether 232 shiploads per year is feasible even under El Paso's best case. The eight-ship fleet, with each ship in service 330 days per year and making a round trip in 11.5 days, can only transport 229.6 shiploads. 1/ By employing the net capacity of 3,378.5 MMcf per ship, the eight-ship fleet could only lift 775,703 MMcf per year, which is less than the 783,665 MMcf to be lifted annually. This would preclude a finding that eight ships could reliably lift the production of the LNG plant, and without some offsetting adjustment by El Paso, its proposed annual LNG lift would not be met. Since this shortfall assumes fully loaded capacity for each of the 229.6 shiploads, one or a combination of the following would be required: increased ship speed or size, reduced time in port, reduced heel, increased number of operating days at the expense of drydock or random repair time. Any of these options, if taken, would reduce El Paso's claim of conservative design parameters.

3. Modifications to Best Case

It is apparent from El Paso's own best-case assumptions in its application, as amended, that the eight-ship fleet as presently constituted can only marginally lift the LNG production if a full 2.4 Bcf/d throughput occurs. At full throughput, moreover, the eight-ship mode has very little flexibility to overcome even the most modest delay. The assumption here is that miscellaneous contingencies will continue to require most, if not all of the 19.2 hours per trip contingency time and that the defined time losses almost certain to occur are additive to the 11.5-day trip time. Another analysis, *infra*, concedes to El Paso the assumption that the 19.2 hours includes most of the known contingencies causing delay. The following discussion makes a number of changes in El Paso's best-case assumptions and assesses whether an additional ship would be needed.

a. Oxnard Terminal

As indicated *infra*, the public convenience and necessity requires that the Western LNG regasification terminal be built at Oxnard instead of at Point Conception. Oxnard is 70 nautical miles south of Point Conception and adds 140 miles to the round trip. This entire increase is through the Santa Barbara Channel,

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1/ Stated differently, 232 shiploads per year at a round-trip time of 11.5 days calls for 8.1 ships. Only if round-trip time is reduced to 11.38 days can eight ships complete 232 shiploads per year (0.66 days rather than the 0.8 day for contingencies El Paso projected or 32.16 days rather than 35.8 days per ship per year).

which, as El Paso recognizes by its 10-knot speed approaching Point Conception, is congested and subject to Coast Guard navigational control. 1/ Accordingly, El Paso's own 10-knot speed within the Santa Barbara Channel will be employed for the increment to Oxnard, which of course adds another 14 hours to the 11.5-day round trip. 2/ With the resulting 12.1-day round trip, the eight-ship fleet could only accomplish 218 shiploads, which provides the capability of lifting only 736,513 MMcf/year, 6% short of the 783,665 MMcf/year LNG production. Therefore, assuming only that the regasification plant is built at Oxnard, a ninth ship must be included in El Paso's fleet. If El Paso were to reduce its 15-day random repair figure to permit one more round trip per year for each ship, which is totally unreasonable, the resulting 226 shiploads could lift only 763,541 MMcf at Gravina. This is short of the annual LNG production of 783,665 MMcf.

b. Port Closure and Other Weather

Returning to El Paso's optimal case, a 10.72-day round trip is found to be the outer limit of what can be achieved in ship scheduling (the 15-day random repair and delay allotment is not considered herein). This is remarkably close to El Paso's own figure of 10.69 days for "the ideal round trip time assuming no delays for weather, port closure, wait for cargo or wait for berth or wait for LNG or wait for storage tank capacity to unload" (52/7758). But port closure, one of the many contingencies already included in the 19.2-hour per trip estimate along with the 15 days allotted annually for random ship repairs and delay, appears to have been treated much too lightly. To the extent that port closure and weather are calculable they reduce the "so-called conservative factor" represented by El Paso as the hallmark of its plan.

1/ No time would be saved by rerouting the tankers to bypass the Santa Barbara Channel. This would require deviation from El Paso's great circle route, and even a cursory examination of a California map compels the conclusion that, circumventing the islands of San Miguel, Santa Rosa and Santa Cruz, would add more distance than El Paso's unrestricted 18.5 knot service speed could absorb in the 14 hours needed to travel through the Santa Barbara Channel.

2/ The assumption here is that El Paso's best case takes 11.5 days, which includes a range of miscellaneous delays. A terminal at Oxnard obviously was not considered in the 19.2 hours per trip "miscellaneous" delay time which El Paso allowed for its best-case assumptions. Adding travel time to Oxnard only to the 10.72 days El Paso uses for its irreducible transit time leaves only 5 miscellaneous contingency hours on an 11.5-day round trip.

El Paso estimated that visibility less than 1 mile would occur only 1.8% of the time at Gravina Point (51/7655-7656, 7664; 52/7783). There is, however, an engineering report prepared for El Paso which stated that the visibility is less than 1 mile 7% of the time (51/7674). 1/ Port closure because of waves (4 feet and greater) could occur 25% of the time from October through April at Gravina Point (EP-98, p. 2A.5-6) and wind (30 mph or greater) around 7.5% of the time throughout the year. (EP-98, p. 2A.3-35). Giving El Paso the benefit of the doubt, these two causes of port closure will be considered to occur simultaneously. 2/ The record further indicates that El Paso, in its simulation, employed port closure figures at Gravina and Point Conception of 11% annually (52/7781). While it is of course possible that such port closure might not directly impact round-trip time, for the present illustrative purpose an assumption of direct correspondence is prudent. Port closure of 11% translates to about 2.6 hours at each port, or 5.2 hours per round trip. Of greater relevance, however, is the potential port closure time during the shippers' peak period. For example, El Paso used port closure figures for December of 20% at Gravina and 22% at Point Conception; this could total 10 hours per round trip in December. Nevertheless, El Paso's December port closure figure of 20% for Gravina could well be increased to 30% to compensate for the 25% wave- and wind- caused closure and the 7% visibility-caused closure, rather than using El Paso's overall 1.8% figure to adjust the estimate.

While the following quantification of this increase in port closure delay is obviously of limited accuracy, the cumulative effect is nonetheless significant. The previously determined 12.1-day round trip (regasification plant at Oxnard) would be increased by 2.4 hours by this additional port closure at Gravina Point. The resulting 12.2-day round trip would lead to a lifting shortfall in December of 6.7%. 3/ While such a deficiency would only be seasonal, El Paso would have to design against it. Even though such a design would result in a lower fleet load factor during the off-peak season, El Paso could not afford to

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1/ El Paso's witness stated that the reference was "unsupported" and, therefore, he did not "assign too much emphasis to it."

2/ There is no evidence on the point, but fog conditions would appear to be inconsistent with high winds.

3/ This percentage reflects, in effect, an annual calculation, in that it uses a 330-day fleet operation. Despite the fact that a higher rate of flat operations would occur in the winter, since all drydock time is scheduled for off-peak periods, a discrete calculation based solely on winter operations would yield a higher percentage shortfall because of the greater LNG plant production required during that period, *infra.*

lose this percentage of LNG plant production, especially since December and the other winter months constitute the peak demand period for most potential shippers. A ninth ship would have to be added for minimum reliability.

c. Drydock and Cool Down

With the present meteorological evidence in the record, it is impossible to accurately assess the exact impact which additional weather-caused delay would have upon the tankers' capability to lift LNG. However, any increase in the allotted drydock time has a direct impact upon fleet capability. There are three sources of potential delay. To begin with, El Paso factors in 2 days for the voyage to drydock, including warming up the ship's tanks and removing the residual gas vapors. El Paso derived this figure from its experience of operating cryogenic tankers and, while El Paso asserts that the time required for the warm-up and gas-free process is not necessarily a function of ship size, the proposed tankers are twice as large as the tankers from which El Paso extrapolated its data (51/7700-7703). Accordingly, it is possible that additional warm-up and gas-free time will be needed, even though there is no doubt that the ships can travel to the drydock (probably at San Diego) within the given time confines (52/7758).

Of greater concern is the 4 days set aside by El Paso for return to service and cool-down. First of all, even with the most optimistic assumptions (2,107 miles from San Diego to Gravina at 18.5 knots), the trip would take 4.7 days. In addition, the cool-down process requires LNG injection into the tanks since the ships themselves do not have the refrigeration equipment. The record does not reflect any west-coast facility which could inject LNG to commence cool-down. Accordingly, it is likely that each ship will have to travel to Gravina (4.7 days) and then begin cool-down. The cool-down process itself would take at least 2 days.

Finally, there is presently very limited west-coast drydock capacity, and the available facilities could be overwhelmed by the scheduled and unscheduled maintenance of the El Paso cryogenic fleet and the much larger number of Alyeska oil super-tankers (51/7699). The record is inadequate to estimate any resulting delay, but this delay for drydock facilities should not be ignored. While El Paso could conceivably take steps to avoid such delays, additional capital and operational costs would have to be assessed against the project.

This discussion indicates that it is conceivable that at least 2 days could be added to the present 20-day drydock allowance, bringing the annual ship utilization time down to 328 days and thereby reducing the annual shiploads, on the basis of a 12.1-day round trip from 218 to 216.8. The annual lifting capacity would be reduced to 732,458 MMcf.

d. Service Speed

The 18.5-knot service speed employed so far in this analysis is illusory. El Paso concedes that 18.5 knots is the service speed in calm water; this makes an average north Pacific 18.5-knot operating assumption completely unrealistic, according to El Paso's own baseline meteorological evidence for the north Pacific ((51/7718);Application, Volume IV, pp. 2F.2-1 through 2F.2-13)). El Paso in fact employed average service speeds of 17.9 knots for the loaded trip and 18.3 knots for the ballast trip (52/7758). These speeds add 4.6 hours to the previously calculated 10.72-day optimal round trip, increasing it to 10.91 days and reducing the 19.2-hour contingency time to 14.16 hours. If these 4.6 hours are added to the 12.1-day round trip, the resulting 12.3-day round trip would allow 214 round trips. Even though El Paso concedes that LNG cargo slamming caused by rough weather or even swell-type waves may require a course change and/or speed reduction (51/7724), it included no time allowance in its simulation for either a direction change or speed reduction (51/7725).

Only a computer simulation can fully digest the aforementioned detailed meteorological data in El Paso's application and give even a rough approximation of average service speed. An adequate appreciation of the problem can be seen, however, from the consideration set forth below. Reducing service speed to 17 knots would add 18 hours (0.75 days) to the round trip, which at this stage of analysis is already up to 12.3 days. The resulting 13.05-day round trip would reduce the number of shiploads (even assuming no further drydock delay) to 202 and the LNG lifted to 682,457 MMcf, a 12.9% shortfall. Under these assumptions, even a nine-ship fleet would be inadequate, being able to lift only 768,901 MMcf. A tenth ship would be required.

e. Coast Guard Navigational System

In its LNG Safety Brief, El Paso recognized that a Coast Guard-operated navigational system will likely be instituted for Prince William Sound. This includes a Vessel Traffic System to control tanker traffic to and from Valdez (EP-74, p. 89). While it is presently impossible to foresee the exact extent of the additional delay, it is reasonable to anticipate regular interruption of El Paso's 18.5-knot service speed as the cryogenic tankers attempt to leave Orca Bay to enter the main shipping lane and pass Hinchinbrook Island or to enter Prince William Sound from the Gulf of Alaska, where vessel separation requirements would prevent full-service speed (ST-22, pp. II 60-61). Until the plan is operational, the length of delays will not be known. But, in light of the volume of shipping from Valdez--the Alyeska tanker fleet numbers about 35 ships (53/7851-7852)--it is reasonable to assume that a 2.5-hour delay each way could occur. This could add another 5 hours to the round trip. 1/

The resulting 12.5-day round trip would permit only 211 shiploads per year, thereby reducing the fleet's lifting capacity to 712,863 MMcf/year, a 9.03% lifting capacity deficit. Under this scenario, El Paso would be forced to use a nine-ship fleet which could lift 802,731 MMcf/year, thereby leaving 2.4% excess lifting capacity in reserve on the same 2.4 Bcf/d full-throughput case.

f. Night Operation

El Paso's simulation assumes 24-hour operation, including docking and ship cast-off at both the Gravina and Point Conception ports (51/7690-7691). Under the Waterways Safety Act, the Coast Guard must give its approval for such 24-hour operation. In this regard, the LNG facility at Boston, which is admittedly in an intown harbor area, is restricted by the Coast Guard to daytime operations (51/7690-7691). El Paso is still discussing with the Coast Guard the operating schedule for its Cove Point, Maryland and Savannah, Georgia regasification terminals (51/7691-7693). A restriction against nighttime docking at either Gravina or Oxnard would obviously require increasing fleet size to 10 or more vessels.

g. Gas/LNG Ratio

El Paso has employed a gas/LNG ratio of 593:1 at Gravina, and this ratio has been employed throughout this analysis. Apparently the gas composition assumed by El Paso, reflecting substantial percentages of heavier hydrocarbons such as propane

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1/ If each of Alyeska's 35 ships and El Paso's 8 ships is assumed to run 26 round trips per year, there would be 2,236 passages annually past Hinchinbrook Island.

and ethane, led to this relatively low ratio. Pure methane has a ratio of approximately 625:1. At the present time, it is not possible to ascertain the final composition of the Prudhoe Bay gas, but if the producers were to remove most of these heavier hydrocarbons presently included in El Paso's assumption, the ratio would increase. This would assist El Paso's fleet lifting capacity. If for example the ratio were increased to 615:1, the fleet's capacity would increase by 3.7%; that is, each ship's net capacity would increase from 3,378.5 MMcf to 3,503 MMcf. At that capacity, the eight-ship fleet would have to make 223.7 trips annually to lift the full plant production; however, as previously determined, it is very doubtful that El Paso could make more than 211 trips. This schedule would lift only 739,133 MMcf. Clearly, even if El Paso were given the benefit of the doubt on gas/LNG ratio, it would still need at least a nine-ship fleet.

4. Alternative Analysis

To test whether the margin of 19.2 hours between the optimal 10.7-day round trip and El Paso's 11.5-day round trip is a conservative cushion which anticipates all additional delays, the foregoing schedule modifications will be reanalyzed by assuming arguendo that the 19.2-hour contingency factor was meant to cover such eventualities. For the sake of this exercise, a restriction on night operations, reduced service speed caused by bad weather on the high sea, additional port closure caused by weather conditions not considered by El Paso, Coast Guard-impaired reduced service speed, and a different gas/LNG ratio are not included.

The 19.2-hour contingency must be reduced by the following: 4.6 hours for the conceded service speeds of 17.9 knots and 18.3 knots for the loaded and ballast trips, respectively; 5.2 hours for the 11% annual average port closure at Gravina and Point Conception estimated by El Paso; and 14 hours for the additional traveling time to the regasification plant at Oxnard. 1/ Just these properly anticipated eventualities alone add 23.8 hours of delay to the 10.7-day optimal round trip. Not only is the 19.2-hour contingency provision exhausted, but another 4.6 hours must be added to the 11.5-day round trip, resulting in a minimum time of 11.7 days. When the amended annual service utilization time of 328 days (2 days were added for return to service and cool-down) is joined to this 11.7-day

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1/ Ignoring the relocation to Oxnard, the other two specific items wipe out about one-half of El Paso's "contingency" allowance and demonstrate that the optimal round trip to Point Conception is at least 11.1 days.

round trip, the eight-ship fleet can only lift 757,708 MMcf, a 3.3 percent lifting shortfall. Accordingly, 8.3 ships would be required to lift the 783,665 MMcf annual production.

Of course, this 11.7-day trip figure is still illusory and inadequate. It provides absolutely no room for other delays, which no doubt will occur. For example, it has already been determined that the 18.5-knot service speed employed by El Paso in its simulation assumed a completely calm ocean. The meteorological evidence of record alone demonstrates the absolute deficiency of this assumption. Just to avoid anticipated LNG cargo slamming, the service speed would have to be reduced. 1/

5. Related Consideration

a. Storage Tank Capacity

Having determined that a nine-ship cryogenic tanker fleet is essential, it is then necessary to determine whether the LNG plant itself needs modification because of the fleet's capacity to lift LNG. Four proposed 550,000-barrel storage tanks have a gross capacity of 349,773 cubic meters. 2/ Some adjustment, however, must be made to this storage capacity. El Paso concedes that maximum net capacity is 96 percent, leaving a 2 percent-ullage space at the top of the tank (51/7683) and 2 percent LNG in the bottom to insure against the loss of pump suction (51/7689). Accordingly, the maximum net storage capacity is 335,782 cubic meters. Translated into a gas equivalent, it has net storage capacity of 7,032 MMcf, which is enough storage for 3.28 days of average day LNG production (2,147 MMcf/d) or 3.01 days of maximum LNG production (2,335 MMcfd). 3/ Moreover, such net storage could fill 2.08 tankers (3378.5 MMcf net capacity).

1/ The "Polar Alaska," an LNG carrier used in the Kenai-Tokyo trade, was out of service for several months because of cargo damage to the ship's hold.

2/ El Paso rounds this storage capacity to 350,000 cubic meters.

3/ The record shows maximum-day plant inlet volumes of 2,531 MMcf. Assuming the same LNG production efficiency rate on a maximum-day basis as is shown by El Paso for average-day operations, maximum-day LNG production would be 2,335 MMcf.

For purposes of this storage/tanker fleet analysis, a 12.3-day round trip, 328-day annual utilization, and 3,378.5 MMcf per ship net capacity are assumed. 1/ These have been proven on the record for the maximum possible 2.4-Bcf/d case. The nine-ship fleet would make 240 round trips, which means that one ship would arrive every 1.52 days. Under such an average arrival schedule, El Paso would need storage for 155,832 cubic meters of LNG, the equivalent of 3,263 MMcf of gas, when the plant is producing 102,521 cubic meters of LNG per day (2147 MMcf/d). El Paso's 335,782 cubic meters of storage could then sustain a tanker delay of 1.76 days (42.25 hours) before the plant would have to cease average-day operations. This of course assumes that El Paso would normally keep a very low storage inventory to keep this capacity available.

This 1.76-day delay storage capacity is not, however, completely accurate. As will be discussed, El Paso plans to synchronize liquefaction train maintenance and cryogenic tanker dry-dock during the summer period, which necessitates increasing liquefaction production to 105 percent during much or all of the period from October through April. El Paso would be operating all nine ships during this 180-day make-up winter period and producing up to a maximum of 2,335 MMcf/d--that is, 111,498 cubic meters of LNG per day. Nine ships, making 126 round trips during this 180-day make-up period (assuming a 12.3-day round trip and a 7.40-day prorated share of the 15-day random repair allowance), would have an average arrival interval of 1.43 days, which means that El Paso would have to store 159,442 cubic meters of LNG between deliveries. The remaining 176,340 cubic meters of storage could permit this production for another 1.58 days (37.9 hours) of delay. With the eight-ship fleet, the permissable delay would only be 1.4 days.

Although El Paso would not always be operating in this turned-up mode, it would do so for substantial periods; therefore, it must design its LNG storage tank capacity for this 1.58-day delay limit. Although there is some indication (52/7784) that the Gravina port would not be closed for 37.9 hours because visibility was reduced to 1 mile, port closure for such a duration between October and April because waves exceeded 4 feet appears likely about 2.2 percent of the time, or 2.5 times during each winter

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1/ In the ship lifting analysis above, El Paso was given the benefit of an 11.5-day trip, which gave no flexibility. Given the unreasonableness of that approach, it is not used here. It would be unreasonable to take a flexibility not shown by the record and apply it to an interface storage which appears also to provide little flexibility.

period (EP-98, tables 2A.5-2 and 2A.5-3). Accordingly, while it is not likely that El Paso's tankers will frequently experience more than the maximum permissable 37.9-hour delay, it will inevitably occur on certain occasions. This leads to the conclusion that a fifth storage tank may be required if El Paso's multicomponent transportation system is to be reliable and free from service interruption.

If there were a design delay -- that is, up to 1.58 days -- it would be essential that delayed tankers could immediately commence loading after their arrival without further delay for cool-down. The potential need for cool-down is the weak link in the fleet/storage interface. Clearly, if a substantial port-closure delay of 1.5 days or greater occurs, thereby backing up two tankers, El Paso's design pumping capacity of 58,000 gallons per minute per ship (EP-62, p.3.1-23) could theoretically fill both ships in 12.27 hours. This pumping capacity appears to provide some reserve to reestablish the fleet's normal schedule. However, the need for cool-down would lessen this reserve capability. As previously discussed, El Paso plans to leave enough heel in each tanker after delivery in California to allow for the 0.15 percent per day boil-off for the ballast trip to Gravina plus 1.5 days of delay. In that the nine-ship fleet would have some reserve lifting capacity, El Paso can and should increase the heel allowance to prevent the need for cool-down even after a design delay.

This analysis leaves no other conclusion than that storage capacity must be increased, either by enlarging the existing tank capacity or adding a fifth tank. Given the fact that El Paso has not completed its design, it is unlikely that this would substantially delay its project. It would, however, add additional costs which cannot presently be quantified. In addition, it shows once again the close tolerance which El Paso has used for a system which, by its very nature, requires greater flexibility to give confidence in its reliability.

b. El Paso Liquefaction Plant

El Paso's liquefaction trains have a design inlet flow capability of 421.88 MMcf/d per train. Thus, the six trains could accommodate plant inlet volumes up to 2,531 MMcf/d compared to annual average-day plant inlet volumes of 2,327 MMcf. 1/ However, the plant design provides for no standby or spare liquefaction trains, and El Paso will be able to employ only five trains when a train is off the line for scheduled maintenance. The design inlet capability of five trains is 2,109 MMcf/d, or about 218 MMcf/d below projected average day operations. El Paso has stated it will schedule its liquefaction train maintenance in off-peak months, when shippers will be better able to adjust to reduced daily deliveries, and will balance fewer deliveries over the year with higher deliveries between October and April. However, the obvious implication of this proposal is that, ignoring whatever minor storage benefits might be afforded by line pack in the upstream 42-inch pipeline and also ignoring constraints imposed from time to time by fleet lifting capability, producers could be called upon to deliver scheduled daily volumes over the year at Prudhoe Bay of roughly 2,100 MMcf to 2,500 MMcf, or a swing of nearly 20 percent. While such a swing in deliveries from a nonassociated gas reservoir would not be unusual, such is not the case here. Oil production rates will determine the availability of gas volumes, and gas once produced must be delivered to market, stored, reinjected or flared.

It is not presently known whether the producers, under the field operating plan to be approved by the State of Alaska, will be able or willing to permit such variations in daily deliveries or whether such variations if permitted, will carry an additional production cost born ultimately by consumers. Any such fluctuations in daily delivery volumes will impact the demonstrably taut balance in downstream LNG storage and tanker capability. Moreover, as shown above, the El Paso eight-ship fleet is underdesigned to adequately accommodate the projected average-day LNG volumes, and even a nine-ship fleet may be incapable of reliably moving peak-period volumes in winter when the risk of port closure is greatest.

1/ El Paso shows that on an annual average-day basis, each train will receive 387.8 MMcf and produce LNG equivalent to 357.8 MMcf for the 2.4-Bcf/d ease. However, since each train will operate only 345 days per year, the average inlet volume per stream-day will be 410.3 MMcf, producing LNG equivalent to 378.6 MMcf. El Paso refers to the average stream-day volume as "100 percent" operations (52/7766). Assuming the same efficiency of LNG production or design capability, an inlet volume of 421.88 MMcf will produce LNG equivalent to 389.2 MMcf.

Under El Paso's 2.4-Bcf/d case, its liquefaction plant, as previously described, consists of six independent but parallel process trains. Apart from the lifting capability of the tanker fleet, it is necessary to scrutinize El Paso's claimed adequacy of the liquefaction plant to process of all the Prudhoe Bay gas production.

On the surface, it appears that the six-train liquefaction plant could produce the 37,421,418 cubic meters of LNG (783,665 MMcf of gas) which El Paso claims can be loaded on the tankers annually. That does not, however, include the maintenance schedule of the plant. El Paso included 20 days per year per train for scheduled and unscheduled maintenance (EP-65, p. 3.1-54; 52/7764). Under the six-train design, that means 120 days annually when the plant is operating with only five trains. For the six-train plant, average stream-day inlet volume is 2,462 MMcf, and LNG production is 2,272 MMcf. During maintenance--that is, for 120 days per year--the plant could only handle an inlet flow of 2,052 MMcf/d at the average stream-day rate and could only produce 1,893 MMcf/d. Moreover, El Paso contemplates this plant maintenance schedule coinciding with the tanker drydock schedule in the late spring, the summer, and the early fall (EP-73, p. 5.4-4). El Paso of course uses a 20 day drydock period per ship, which, under the eight-ship fleet, means 160 days per year when the fleet is only seven ships strong.

For the purpose of this analysis, the aforementioned probability that the field production flow would not be altered to suit El Paso's schedule is ignored. The resulting questionable scenario is nonetheless analyzed to demonstrate the inadequacy of El Paso's six-train design under the 2.4-Bcf/d case. During this 120-day LNG plant maintenance period, the five trains operating at 100 percent, i.e., average stream-day output, could produce LNG equivalent to 227,160 MMcf. Since the tanker fleet would simultaneously be operating with seven active ships, the lifting capacity for that period would be 221,312 MMcf. (This figure includes the previously determined 12.3-day round trip, the 3,378.5 MMcf net capacity per ship, and the proportionate share--4.9 days--of the 15-day allotment for random repair and delay.) El Paso would have to decrease LNG production per train from the 100 percent to accommodate tanker lifting capacity.

There would be a 40-day period when the LNG plant was operating on six trains while the fleet was still only seven ships strong, caused by the 160 days of drydock versus the 120 days of LNG plant maintenance. During this 40-day period, the seven-ship fleet could only lift 73,739 MMcf. (The 12.3-day round trip and 3,378.5-MMcf net capacity were employed, along with the proportionate share--1.65 days--of the 15-day random repair period.) Unfortunately, while the six-train plant could produce 90,864 MMcf at the 100 percent rate during this 40-day period, the fleet lifting capacity would force a production reduction for that period.

For this 160-day period, El Paso would have produced and lifted 295,051 MMcf, leaving 488,614 MMcf to be produced and lifted in the remaining 205 days. It appears that El Paso plans to compensate for the earlier underproduction from October through April. To begin with although all eight ships would be in operation during this period, they would be able to lift only 432,007 MMcf. (Based on the 12.3-day round trip and 3,378.5-MMcf net capacity, the proportionate share--8.4 days--of the 15-day random repair period is included.) If El Paso could run each train at the design inlet flow of 421.88 MMcf/d, the total inlet flow of 2,531 MMcf/d would produce 478,675 MMcf of LNG equivalent over the 205-day period. Not only is this less than the needed 488,614 MMcf and more than the lifting capacity of the eight-ship fleet, but it is also questionable that prudent practice would permit the plant to operate at that rate for that period.

Since it has already been determined that at least nine ships are needed, the analysis above will now be repeated with nine ships. To begin with, during the 120 days when the plant is only operating with five trains and one ship is always in drydock, the remaining eight ships could lift 252,919 MMcf; however, the plant would only produce 227,160 MMcf at the 100 percent rate and therefore could not fully utilize this lifting capacity. In fact, the five trains to operate at design inlet capability could produce LNG equivalent to only 233,520 MMcf, and thus full fleet lifting capacity could not be utilized.

Instead of a 40-day period when the plant is operating with six trains and the fleet is still short one ship, this period would now be 60 days. The eight ships could lift 126,437 MMcf (under the same assumptions as before). While the six-train LNG plant, producing at the 100 percent average stream-day rate, could produce more than this amount over this same 60-day period, the production would be limited to the 126,437-MMcf fleet lifting capacity.

During this 180-day period of simultaneous liquefaction plant maintenance and cryogenic tanker drydock, El Paso would be able to produce and lift a maximum of 359,957 MMcf. Therefore, in the remaining 185 days, mostly likely October through April, El Paso would have to produce and lift 423,698 MMcf. The full nine-ship fleet, having the scheduled maintenance behind it for this 185-day period, could lift 438,547 MMcf. But this figure is questionable, since the port-closure rate during this 7-month period is greater than the 11 percent annual average; it is 15.15 percent at Gravina and 14 percent at Point Conception (52/7781). If the plant were to operate at the maximum design inlet flow of 2,531 MMcf/d (421.88 MMcf/d per train) to produce 2,335 MMcf/d for the entire 185-day period, it could conceivably produce 431,975 MMcf, or 2.0 percent more than the scheduled amount (a 2.4 percent production shortfall).

Under the nine-ship case, the only way El Paso could annually produce and lift the claimed 783,665 MMcf would be to increase the five trains during the entire 120-day summer maintenance period to design capacity and operate within 2 percent of capacity during the 185-day, October-through-April period. This apparent sufficiency of the six-train liquefaction plant is, however, illusory, because the aforementioned assumption that the five trains run at design capability for the entire 120-day maintenance period suggests questionable operating practice. With one train down for maintenance during this entire 120-day period, El Paso would already approach serious service interruption, and it would be imprudent to risk forced outage of another train by running each train at capacity.

It is clear from the foregoing discussion that, similar to shipping capacity and LNG storage, the proposed six-train design does not contain sufficient flexibility to assure the necessary reliability of service which ratepayers are entitled to expect with El Paso's proposed 2.4-Bcf/d case. Accordingly, any comparative analysis of the El Paso 2.4-Bcf/d project should include not only a ninth cryogenic tanker but also a seventh liquefaction train. 1/

1/ If the Prudhoe Bay volumes come in at a level less than 2.4 Bcf/d--say 2.25 Bcf/d--El Paso's proposed design gains some degree of flexibility, but at the expense of higher unit costs.

Even if the benefit of every doubt were given to El Paso, it is totally unreasonable to claim system reliability without a standby liquefaction train. It is stretching credibility to design without considering untimely, or indefinite, forced outage of any one of six trains over any extended period of time.1/ No finding can be made that this proposed design meets the public convenience and necessity.

6. Summary

There are no astounding conclusions to be drawn from this exercise on ship carrying capacity and the interface of the various components of this complex technology. El Paso has given a best-case presentation of its operations over the years which leaves no flexibility. It is simply not credible as presented.

However, while additional or enlarged facilities clearly are required, dollar cost associated with such additions or enlargements will not necessarily reflect the cost of an additional LNG train, storage tank or ship. El Paso may choose to show reliability at a lower throughput or to enlarge and redesign components. Thus, while a comparison in the economic sections, *infra*, reflects the increased costs of an extra LNG train and a ninth ship, less costly solutions are in all liklihood possible.

The above observation is borne out by El Paso's late-filed submission of a "sensitivity" study of its fleet designs. Toward the close of the hearing, it became apparent that Oxnard was a very viable alternative to the Point Conception proposal. El Paso was asked, therefore, to submit a study showing its computer simulation of an eight-ship lift between Gravina Point and Oxnard. By letter dated January 3, 1977, El Paso submitted an extensive "study" showing that the additional haul would require redesign of its ships from their present 165,000-cubic meter capacity to 175,000 cubic meters to accommodate the additional distance. This came as no surprise. During the time the analysis was being made in this section of the Initial Decision, it was evident that a ninth ship or redesign of fleet capacity would be required solely by adding the additional Oxnard trip time to El Paso's very tight, precise schedule. No evidentiary weight can be given or will be given to this study, however, since the other parties have not had an opportunity to fully test either its premises or its ultimate conclusion.2/

1/ This is an application of Connolly's Law. Murphy's law: If it can go wrong, it will. Brackett's law, as coined by El Paso: If it is necessary for Arctic Gas to succeed, it will occur; Connolly's Law: Murphy's law is only for the competitors and Brackett's law, modified to fit El Paso, is only for El Paso.

2/ The question is immediately raised, for example, whether in designing up to 175,000 cubic meters, El Paso will be able to realize that "block coefficient" advantages claimed for its 165,000-cubic meter design.

7. Tanker Fleet Simulation Model

In the prior section it was demonstrated that under the 2.4 Bcf/d case El Paso would have to operate a ninth 165,000 cubic meter cryogenic tanker in order to reliably lift the proposed annual volumes of LNG of 37,421,418 cubic meters (783,665 MMcf of gas). In the instant section a computer simulation was performed which provided the same result.

This simulation model is based upon a formula provided by the Division of Economic and Operational Analysis of the Federal Maritime Administration. This formula is used to determine fleet size and is based upon route, cargo and ship characteristics. This basic model was then elaborated to include effects of weather and service speed restrictions.1/

While a detailed description of the cryogenic fleet simulation model, including program listings, appears in Appendix E, a brief explanation of the elaborated formula underlying the model is herein presented: In order to determine the number of ships in the fleet, the annual cargo load is divided by the product of multiplying LNG shipment size by the result of the following division -- annual operating days divided by the round trip time, which is the sum of the distance divided by the product of speed times 24 for each segment of the journey plus part time delays.2/ The following adjustable inputs are employed in the simulation: annual operating days, shipment size, actual annual cargo lifted, series of part time delays, and trip segments and weather.

The following computer model simulation runs corroborate the need for a ninth ship:

1/ By FPC staff personnel who were not involved in the trial of this proceeding and who were detailed to the Presiding Judge.

2/ Number of ships = annual cargo load

$$\text{Number of ships} = \frac{\text{annual cargo load}}{\text{shipment size of LNG} \times \left[\dfrac{\text{annual operating days}}{\text{number of segments} \times \left(\dfrac{\text{distance}}{24 \times \text{speed}}\right) + \text{part time delay}}\right]}$$

1. Under the best possible case for El Paso, 7.981 ships would be needed. The inputs included are 330 days annual operating days, 161,337 cubic meter shipment size, 37,421,418 cubic meter annual LNG cargo lift, 1.42 day and 1.32 day port delays at Gravina and Point Conception respectively (52/7771), 10 nautical miles between ports each direction at 18.5 knots, and 6 nautical miles into and out of Gravina at 14 knots. These port delay and journey segment inputs result in a 11.35-day round trip. If El Paso's own 11.5 day figure is employed, 8.085 ships would be needed.

2. If the regas plant is moved to Oxnard, thereby adding 70 miles at 10 knots in each direction, 8.391 ships are needed. All other inputs remain the same.

3. When the service speed is reduced from 18.5 knots to 18.3 knots for 1886-mile ballast trip and 17.9 knots for the 1886-mile loaded trip, as El Paso conceded on cross-examination should be used, the number of ships needed increases to 8.523.

4. Together with the above preceding two input changes reduction of the annual operating days to 328, to account for another two days for the ships to return to service and cool-down after drydock, increases the number of ships needed to 8.575.

5. Reduced service speed in and out of Prince William Sound also has a delaying impact. When the 14-knot speed employed by El Paso for the last six miles is applied to the approximately 50 from the entrance of Prince William Sound to Gravina and added to the inputs in the three preceding paragraphs, El Paso needs 8.617 ships.

6. If on the other hand, future navigational controls increase this delays up to a reasonable figure like 2.5 hours in each direction, 5 hours per round trip, and this time were added the 1.42-day port delay at Gravina to give a 1.63-day port delay, the number of ships needed would be 8.724.

7. If El Paso were in fact unsuccessful in obtaining Coast Guard approval for 24-hour berthing and departure at Gravina and Oxnard, additional average delays of 0.74 days and 0.58 days would be added to Gravina and Oxnard port delay, respectively 9.551 ships would be necessary under such circumstances. If this restriction on night operations applies solely to Oxnard, 9.027 ships would be required.

8. Including the input changes in paragraphs 3, 4, and 6 to the ideal case found in paragraph 1 (return of the regas plant from Oxnard to Point Conception) still results in the need for 8.311 ships.

9. As will be detailed in Appendix E, the computer simulation model has also been structured to digest El Paso's trade route baseline meteorological evidence (Application, Volume IV, pp. 2F. 2-1 through 2F. 2-13). When this weather data is included in the simulation, the round trip time increases, thereby reinforcing the need for a ninth ship.

When weather is added to El Paso's best case, supra paragraph 1, the 7.981 ship figure increases to 8.080 ships. Perhaps the most probable scenario, however, is found in paragraph 5 above: that at 328 annual operating days, Oxnard instead of Point Conception, reduction of service speed for 50 nautical miles in and out of Prince William Sound to 14 knots, and average service speeds absent weather of 17.9 knots loaded and 18.3 knots unloaded. These inputs lead to 8.617 ships. Inclusion of the weather inputs increases that to 8.717 ships.

Examination of this last computer run shows service speeds through the many weather segments of the trade route which generally correspond to the 17.9 and 18.3 knot average service speeds mentioned by El Paso's witness Schmitt. He had previously testified that El Paso did not use a weather input, but, if one were to assume that in fact the 17.9 and 18.3 knot service speeds reflect the trade route weather data, thereby converting the base speed back to 18.5 knots, El Paso would still need 8.584 ships.

10. In anticipation of a possible El Paso rejoinder that, if it were actually assessed a ninth tanker by the Commission, it would instead reduce the volumes to be processed and delivered, the foregoing computer simulation was also operated on the assumption of 8 ships.

Under the preceding scenario in paragraph 9 in which 8.717 ships were derived, an 8-ship fleet could only lift 34,345,136 cubic meters of LNG annually, which is only 91.78% of the 37,421,424 cubic meters which should be lifted annually under the 2.4 Bcf/d case. This reduction in deliveries to maintain an 8-ship fleet, of course, will have a definite escalating impact upon the unit transportation cost to be charged by El Paso

If the alternate scenario in paragraph 9 were employed, the 8-ship fleet could lift 34,874,320 cubic meters, only 93.19% of the proposed volume.

J. Alcan--Engineering and Geotechnical

The other applicants and Staff criticize Alcan's engineering and geotechnical design for being so unsupported by meaningful design preparation as to make it extremely difficult, if not impossible, to determine the feasibility of its project proposal. This criticism is painfully accurate. Alcan's seismic and geotechnical designs lack the necessary preliminary studies to permit a finding that Alcan's cost estimates are reasonable. 1/

An analysis of several specific areas of Alcan's showing must be made. While there is no serious seismic risk along Alcan's alignment from Prudhoe Bay to Delta Junction, that is not the case from Delta Junction to the Alaska-Yukon border: the Denali fault runs somewhat parallel to the Alcan alignment about 25 miles away. It is apparent from Alcan's seismic evidence that it has not yet factored such recognized seismic risk into its preliminary design and, at the time of the hearing, it was only in the process of beginning the needed seismic studies (204/35,027-35,028, 35,040-35,041). Moreover, whereas El Paso's seismic design included design time and additional capital costs in its original proposal to account for more specific seismic research and engineering, Alcan's provides neither.

Alcan also did not precede its initial design and cost estimates with even preliminary geotechnical research. Except for the Prudhoe Bay-to-Delta Junction segment where Alyeska's soil data (core samples) and revegetation plan, if studied, would offer valuable assistance, Alcan had hardly attended to such important geotechnical considerations as soil data, revegetation, permafrost degradation, frost heave and slope stability. Even though no

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1/ The Alcan project's total cost estimates cannot be fully analyzed. Given AGTL's announced intention to change its allocation methodology to a rolled-in basis, which appeared for the first time in its Allocation Rebuttal Brief filed December 15, 1976 (p. 19), Alcan destroys by its own admission its cost submission. Its argument that the intended rolled-in costs represent a saving to U.S. consumers, moreover, is more than sufficient vindication of Staff and those parties which have argued throughout that its Canadian sponsors' allocation methods would be unfair and more costly to U.S. consumers. See also Allocation section, *infra*.

doubt has been raised that it is possible to construct and operate a geotechnically sound pipeline along or near Alcan's proposed alignment, there is serious question whether it could be done under Alcan's construction schedule and cost estimates as filed.

A significant aspect of Alcan's proposal, which diverges greatly from the other applicants' proposals, is extensive summer construction in permafrost regions. 1/ Alcan has proposed to construct the pipeline in Alaska from mid-April to October (river crossing construction would have scheduling flexibility for environmental purposes) because of the lower productivity inherent in winter construction. Alcan views permafrost degradation from summer construction as minimal: it discusses trench-melting as slight (1 or 2 feet) because of the short period (2 to 3 weeks) between ditching and backfilling and states that construction in difficult permafrost areas (hillside slopes) could be deferred to the colder months when the ground is frozen.

It is clear, however, from Staff's geotechnic evaluation of Alcan (ST-51, pp. 177-185) that summer construction in Alaska cannot be accomplished without unacceptable environmental impact. Degradation of ice-rich permafrost results from summer construction. Depending on the specific topography at any given location, one or more of the following effects of degradation could occur: thermokarst (differential thaw settlement or ground caving caused by ground ice melting); mass wasting, including solifluction (downslope movement of saturated nonfrozen earth); drainage pattern changes; thaw consolidation; increased potential for frost heave (the thermal degradation would create a deeper thaw bulb); and erosion of permafrost from increased exposure to wind and running water. 2/ Avoiding summer construction across much of Alaska

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1/ It is a curious fact, moreover, that, while Alcan proposes summer construction in Alaska, its Canadian partner, Foothills, under identical or similar geotechnical conditions, proposes winter construction in the Yukon.

2/ Assuming that the melt would be only 1 to 2 feet, the melting would be in three directions. In ice-rich soils, such construction could result in an 8-foot wide hole increasing to 10 to 12 feet wide with a stream or pond at the bottom. Since borrow would have to be used as back fill, gravel needs and costs surely would escalate.

requires Alcan to revise construction schedules and cost estimates upward. In this process, much of its alleged scheduling and cost advantage disappears.

Nor does this record permit a finding that Alcan's alignment on Alyeska's right-of-way is in the public interest. From Prudhoe Bay to Delta Junction, 539 miles, Alcan's proposed alignment would closely parallel the Alyeska oil pipeline. In fact, Alcan proposes to use the Alyeska gravel work pad, burying its line on the other side of the pad from the oil pipeline. Apart from the previously found serious threat of damage to the then-operating Alyeska pipeline from either El Paso or Alcan construction in such proximity when making limited and discrete crossings, the preliminary nature of Alcan's engineering design alone precludes any approval of Alcan's proposed alignment which would literally be cheek-to-cheek with Alyeska for hundreds of miles. Specifically, Alcan has left unanswered several critical questions, the net result of which would be to require realignment away from the Alyeska line and closer to El Paso's original alignment, which is the only alignment that could be certificated given the present state of the record.1/

Because of the thermal sensitivity of the vertical support members (VSM) for the 50% aboveground portion of the Alyeska line, Alcan must show that it can blast an open ditch in the summer, within 25 to 50 feet of the VSM or buried pipeline, without weakening the frozen aggregate VSM foundation or creating a different heat flux which could cause unknown thermal changes. The further Alcan must move from the Alyeska right-of-way, the less valuable are Alyeska's core samples, and the more gravel pads and roads Alcan must build. None of these were or could be quantified. It is no wonder Alcan has received no response from Alyeska on either its willingness to share the work pad or the minimum allowable distance between the two lines, and, absent such studies, Alyeska could not give such approval without jeopardizing its own line.

1/ It should be noted that some of the studies necessary to evaluate Alcan's plan to use the Alyeska work pad could be time consuming and might never overcome the approach that, to be conservative, the answer is "no."

Unlike blasting near a natural gas pipeline, which entails limited environmental risk, a mistake in Alcan's blasting could result in a break releasing substantial quantities of hot oil. Even if Alyeska were to permit Alcan's parallel alignment and construction off of its work pad, there is an obvious need for a substantial team of Alyeska onsite supervisors to avoid construction damage to the Alyeska line. Alyeska would probably insist on a veto right over final design as well as the right to stop construction if it feared damage to its line. Alcan has not factored these costs into its estimates and construction schedule.

K. Summary

All three pipeline construction plans are built, block by block, on the continued expansion of pipeline construction techniques into more and more inhospitable environments. The experience of Alyeska and the development of Prudhoe Bay combine buried and above-ground pipeline construction, new techniques of vertical support members (VSM) for pipelines frozen into the permafrost, construction under winter conditions, logistic problems, and a host of other practical problems calling for innovative solutions. The experience to date is that these new techniques have worked, but at a price. The representations made here are that the prior experience has been digested, the costs properly assessed and included, and the time frames adjusted to reflect accumulated knowledge. These representations are credible. It is found that, except for those adjustments made in the Economics section, infra, to reflect reasonable additional costs which in all likelihood will flow from construction adjustments, the Arctic Gas and El Paso lines can be built in the manner and in the time frames proposed.

Basically, any pipeline design deficiencies which exist for El Paso and, to a greater extent, Alcan can be resolved by Arctic Gas' solutions for comparable problems. Final design on El Paso's alignment, given the route and the year or so available for further work, could be accomplished. Coring samples could be made on an accelerated schedule at a greater cost, as could seismic design parameters and seismic design. Only a small portion of pipe is affected by seismicity, and the rest of the pipe could be ordered along the critical path necessary for scheduled completion. If the design changes made by Alyeska, even at the time it was installing its pipe, are a guide, these changes and shifts will occur not only on small alignments but possibly on large sections of pipe as well. They are costly, for time and money have a symbiotic relationship, and the shorter the time to arrange the solution, the higher the dollar cost to overcome the deficiency.

On these cost issues, El Paso, primarily through its lawyers, has made a silk purse out of a sow's ear. It has done little intermediate design work and its design, while impressive on paper and in the strip maps, has no particular backup by core samples or even general site-specific work anywhere along its actual route. At Gravina Point and through the Chugach Mountains in particular, this omission is significant. Arctic Gas is right in asserting that El Paso's 5% contingency for cost overruns is elastic, stretching like Skidbladneer to cover each and every general deficiency. 1/ Nevertheless, the conclusion is warranted that El Paso can build its pipeline in the time proposed and not too far from the dollar figures it used for comparison purposes. While additional costs could be suggested, absent any more underlying data than received in this record, the additional costs would also be subject to a charge of being arbitrary, even if more "reasonable." The need for additional LNG facilities is another matter.

Alcan itself has not met its burden of proof on construction schedules and its 3-year phased-in construction plan is not supported by the evidence. Alcan, however, is composed of experienced and knowledgeable companies, at least two of which have extensive experience in building pipelines in both difficult terrain and extreme climates. The result is that while it has not proved its design or costs, Arctic Gas and El Paso have proved Alcan's general design feasibility and placed outside limits on Alcan's expected costs. At one point or another, a portion of both Arctic Gas and El Paso would go through similar terrain or would be built under similar conditions. The El Paso base alignment costs from Prudhoe Bay to Delta Junction can be said to indicate in general what Alcan construction would cost for the same distance. 2/ Mile for mile, Alcan construction costs from Delta Junction east can be assumed to be no greater than a similar mile for El Paso's 42-inch line just north of Delta Junction. In other words, while Alcan did not adduce the evidence to make its case, its piggybacking on those that did gives at least an approximation of what it might cost for comparison purposes.

1/ The boat of the Norse gods, small enough to fit in a pocket, but elastic enough to carry all the gods who wanted to be transported.

2/ If Alcan had to follow El Paso's base alignment right-of-way, it can be assumed that Alcan's engineers would build to their own specifications at costs not too dissimilar from those of El Paso's higher pressure line.

V

OPERATIONS

The most significant operational factors raised on the record involve fuel usage, heating potential or Btu content (measured in Btu's), limitations on transportation capability, and cheap expansibility. While exact fuel-usage and Btu content calculations cannot be made at this time, it is found that Arctic Gas enjoys significant fuel-usage advantages over El Paso and Alcan and that Arctic Gas and El Paso are both capable of transporting gas with a higher Btu content than Alcan.

A. Fuel Usage

It is clear that none of the proposed systems will be able to deliver all of the natural gas entering its line at Prudhoe Bay. While all three projects will use natural gas to power the gas turbines which drive their pipeline compressors, the El Paso system will use additional natural gas at the liquefaction plant in gas turbines to drive compressors for the refrigeration circuits and for ship fuel and at the regasification plant to raise the temperature of the gas or provide supplemental vaporization heat. 1/ El Paso will also require bunker fuel oil to supplement LNG boiloff as ship fuel, a small amount of diesel oil at the liquefaction plant, and electricity at the regasification plant.

It is undisputed that Arctic Gas, because of its large-diameter, high-compression pipeline, will require less fuel than El Paso or Alcan to transport the same system inlet volume. Since gas consumers must pay for the gas consumed as fuel, reduced fuel usage results in lower unit costs to the consumer. Furthermore, the replacement cost of gas not received because of higher fuel consumption is an additional aspect of fuel usage comparison. Arctic Gas suggests a $12/barrel cost for foreign oil as a conservative estimate of the replacement cost. Finally, this replacement fuel will doubtless have some degree of adverse environmental effect compared to natural gas usage.

1/ Alcan witness Edward Mirosh testified that Alcan is considering the use of electric motor drivers in place of gas turbine drivers, but this would depend on a number of factors, including a hydroelectric system not yet built (253/44,392-393).

1. Arctic Gas v. El Paso

The following table shows the fuel requirements of the various segments of the El Paso and Arctic Gas systems.

EP:	2.25-Bcf/d case 1/	2.4-Bcf/d case 2/	AG: 2.25-Bcf/d case 3/	
	% Inlet	% Inlet		% Inlet
Alaska Pipeline	1.29	1.46	AA Pipeline	-
Liquef. Plant	5.43	5.39	CAGPL Pipeline	5.87
Ships	1.59	1.59	West. US Pipelines	(0.14)
Regas Plant	0.08	0.19	Midwest/East Pipelines	1.14
Lower-48 Pipelines	3.17	2.26		
	11.56%	10.89%		6.87%
Non-gas	1.57		Non-gas	-
	13.13%			6.87%

Column 1 of the above table is Arctic Gas' adjustment of El Paso's project to a 2.25-Bcfd case for comparative purposes. El Paso admits that the only disagreement is over projected lower-48 pipeline fuel requirements, which Arctic Gas has estimated will be 1 percentage point higher than El Paso's projection. 4/ It is impossible to determine, from the record, the exact fuel requirements for El Paso's proposed lower-48 transportation-displacement scheme. El Paso argues, on brief, that its figure reflects even less spare capacity (thus higher incremental fuel usage) on shippers' pipeline systems than was testified to by the various shipper witnesses. Moreover, it avers that Arctic Gas' projection is based on outdated data. It is not necessary for the findings made herein to resolve this minor discrepancy at this time. Even if El Paso's lower-48 fuel usage is assumed to be only 2% on a 2.25-Bcfd basis, 5/ its total fuel usage would still be 11.96% compared to 6.87% for Arctic Gas. This represents a substantial annual saving, exceeding residential consumption in each of a large number of states.

1/ AA-93

2/ EP-265

3/ AA-93

4/ In summary, El Paso has neglected to portray the nongas usage on its system. This apparently is not caused by any disagreement over this figure, however.

5/ El Paso's own figures show 2.26% for its 2.4-Bcfd case and 2.85% for its 3.2-Bcfd case.

In its calculations concerning comparative costs of each system, Arctic Gas has accepted El Paso's projections of the fuel usage at its LNG liquefaction plant. However, as has already been found in the construction section, supra, Arctic Gas' skepticism about whether El Paso will be able to meet its presumed fuel savings is well supported.

Thus while El Paso's estimates are accepted for the purposes of this comparison, it is important to recognize the likehood that fuel usage at the liquefaction plant will be greater than El Paso has estimated.

2. Arctic Gas v. Alcan

It is clear that the higher-pressure, larger-diameter pipeline of Arctic Gas (48-inch, 1,680-psig) allows higher throughput, less horsepower and less fuel than Alcan's system (42-inch, 1,250 psig). Table E of the Arctic Gas Initial Economics Brief is a work paper schedule prepared by Alcan. This schedule shows a fuel usage for Alcan of about 13.2 percent, not including displacement fuel on Nothern Border. (Arctic Gas' fuel usage is 6.3%, not including such displacement.) Alcan does not refute the fuel-usage figure. Moreover, if it is accepted that replacement fuel should be considered, Arctic Gas has estimated the price of replacement fuel for this differential at $100,000,000/year (Arctic Gas Init. Eco. Brief, 8).

Although the comparative fuel-usage figures cited above are clear enough indications of Arctic Gas' advantage over Alcan, several other arguments were made by Arctic Gas which make the differential even more pronounced. First, it is argued that Alcan assumed a pipe roughness factor--used in pipeline design flow studies to approximate the friction losses in the pipe--well below 300 micro-inches for some of its pipeline, while Arctic Gas used 300 micro-inches. Increased roughness requires more horsepower. For instance, an assumption of 200 micro-inches instead of 300 improves the predicted capacity of the pipeline by about 2 percent. While the effects of the actual internal pipeline roughness will not be known until operations begin, it is apparent that Alcan's assumption gave it an unmerited advantage over Arctic Gas. There is no reason to suppose that Alcan can get smoother pipe or that it will be internally coated differently or better (245/42,760).

Similarly, Arctic Gas argues that Alcan used the Starling and Han modification of the Benedict-Webb-Ruben equation of state in evaluating gas properties for its flow calculations. Arctic Gas used the so-called "AGA method," which has the effect of predicting increased pressure losses in the pipeline and thus increased horespower requirements (245/42,761). Again, it is not significant for this discussion which method is more accurate. What is important is that the Alcan precedure has resulted in understating its fuel usage compared to that of Arctic Gas.

One other factor concerning Alcan's fuel usage is critical to a number of its arguments. Alcan has maintained that it can increase throughput on its 42-inch line to 2.9 Bcfd without looping However, Alcan witness Edward Mirosh conceded on cross-examination that Alcan can increase compression to reach 2.9 Bcfd only at a tremendous cost in fuel consumption. In fact, this 20% increase in volume would require doubling the fuel usage--fuel use would go up 113% (253/44,404). Mirosh concluded that looping would be recommended to handle a throughput of 2.9 Bcfd (253/44,403-413). 1/

B. Btu Content

Before entering the pipeline, the natural gas must be conditioned for dew-point control, i.e., a portion of the heavier liquefiable hydrocarbon must be removed to avoid condensation of liquids in the pipeline. There is no dispute that the operating pressure level of a pipeline determines its dew-point specifications and that higher-pressure lines are able to carry more of the heavier hydrocarbons, which have a higher Btu content. Thus, Arctic Gas and El Paso are able to accommodate a richer gas stream than Alcan, i.e., gas with a higher Btu/cf ratio.

Based on the simple "flashing" technique of conditioning, in which none of the liquids removed from the stream are returned to it, Arctic Gas can carry 1,145 Btu/cf (at 14.696 psig), while Alcan can carry 1,122 Btu/cf. On rebuttal, Alcan claimed that a more sophisticated processing technique would allow the injection of the lighter dissolved gases (methane, ethane, propane) back into the gas stream. The result would be to raise the Alcan gas to 1,137.8 Btu/cf. Alcan claimed that the same technique would raise Arctic Gas' heating value to only 1,148.2 Btu/cf (AP-23). However, cross-examination revealed that Alcan assumed that it would flash its gas at -15° and 500 psig., while Arctic Gas would flash its gas at +150 and 800 psig. The result of this difference is that Alcan's Btu value would rise disproportionately more than that of Arctic Gas. In fact no rationale was presented showing why both

1/ Alcan's only response to all of Arctic Gas' arguments seems to be that if Arctic Gas were forced to operate at 1,275 psig, its fuel usage too would be 41% higher. This is not a persuasive response.

projects could not use exactly the same technique to achieve similar Btu enrichment. Alcan witness Norman Carnahan testified that he did not study the Arctic Gas system using the same procedures as those planned for Alcan. Arctic Gas on brief states that it could raise its heating value to 1,168 Btu/cf using the lower flash point (Arctic Gas Rep. Eco. Brief, 25-26). The Alcan argument that there is no record evidence of this is specious. Unless the contrary is proven, one must assume that like systems can benefit from the same technology. 1/

Alcan concedes, in any event, that Arctic Gas can still carry more of the heavier hydrocarbons through its pipeline. However, it argues that the liquids that are not carried by Alcan will not be "lost." Rather, most of the butanes would be used for fuel within the conditioning plant, while the remaining butanes and all the heavier liquids would be transported south through the Alyeska oil line. 2/ Moreover, Alcan asserts that the entire Btu question may be moot, since the producers may reserve the right to strip the hydrocarbon liquids on the North Slope. 3/ See also supra.

Regardless of the events which may occur to resolve these present imponderables, it is clear that Artic Gas and El Paso will be able to transport natural gas with a higher Btu content to the designated markets than Alcan can.

C. Cheap Expansibility

The dispute over whether cheap expansibility is available really involves two different issues: (1) easy expansibility for transporting additional gas in the existing systems as designed without substantial additional construction cost, and (2) availability of that capacity for U.S. volumes. Only the entire Arctic Gas system and the El Paso system from Prudhoe Bay to its Alaskan marine terminal facility have the former.

Alaskan Arctic can handle larger volumes of Alaskan gas--up to 4.5 Bcfd--with the addition of compression; only Canadian Arctic can accommodate total U.S.-Canadian volumes up to 4.5 Bcfd on the same basis. If the volumes which now appear likely in the short run from the Mackenzie Delta (1 Bcfd) are all that materialize,

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1/ It should also be noted that the different treatment Alcan accorded the two projects in AP-23 was clarified only on the last day of hearings.

2/ The cost consequences of such disposition of the liquids are not resolved on the record. Nor is there any evidence of the volume of hydrocarbon liquids which the Alyeska line can efficiently transport.

3/ Given the economics of building an extraction plant on the North Slope, it is more likely that liquids will be removed at a point downstream, like Caroline Junction.

the Arctic Gas system could carry up to 3.5 Bcfd of Alaskan gas at comparatively low incremental capital cost. In fact, the overall unit transportation cost would likely be less after such expansion than before. If volumes in Alaska grow to exceed 3.5 Bcfd and those from Mackenzie Delta surpass the early volumes now predicted, the more expensive expansion by looping, while needed, would be a work of joy. The point is that it would take volumes of that magnitude to use up the easy expansibility which the other two systems do not have to begin with.

El Paso's expansibility beyond its 2.4-Bcfd case--aside from the increased flow in the pipeline which can go to 3.2 Bcfd without significant costs--requires LNG trains, ships and time. Such expansion would be neither cheap nor rapid compared to the same anticipated Alaskan volumes which Arctic Gas can move. If the issue is solely that of physical facilities, the El Paso system is obviously not cheaper. El Paso's high capital expenditures for compressors, LNG trains and ships begin as soon as 2.4-Bcfd production (or perhaps 2.2-Bcfd production, as shown in the Construction section, supra) is reached, whereas if the current projections of Mackenzie Delta supply hold true, Arctic Gas can expand to 3.5-Bcfd production of Alaskan gas with only increased capital expenditures for compressors.

Alcan's claim of cheap expansibility is nothing but a claim. Alcan proved in this case only that it would build a line capable of transporting 2.4 Bcfd at 1,250-pound maximum pressure. As nicely put by Staff on brief (Position Brief p. 17):

> ...The filed for 1,250 psig initial maximum design pressure with a very tentative future escalation to 1,440 psig with experience, became as the hearing progressed the 1,440 psig/design derated in early years to 1,250 psig.

No Alcan policy witness testified that its pipeline would operate at the higher pressure. Its technical witnesses testified that, after several years of operation, attempts to "jack" it up to higher pressure would be warranted and, if the tests were successful, it could be so operated. Alcan's expansibility, which it refers to from time to time as permitting 3.1 Bcfd, is based upon increasing compression, which since it exceeds the original design, uses inordinate and unacceptable amounts of fuel. 1/ Alcan will have to expand its line by looping to carry any increased volumes efficiently and, if any additional volumes are projected for the early years, Alcan's line will be obsolete as the pipe is put in the ground. So will its cost estimates.

1/ Alcan's analysis in its Wrap-Up Brief (p. 15) begins by derating prospective Alaska production to only 2 Bcfd and then rating its line capacity to an unrealistic 3.1 Bcfd. It concludes it has a 45% "cheap" ability to expand. Comparisons based upon such "selected" basis are not worth much.

VI

ENVIRONMENT

A. NEPA

The National Environmental Policy Act, 42 USC § 4331 et seq., requires that sufficient information be made available to decision-makers to enable them to take a "hard look" at the environmental interests in a case. The intent of NEPA is to foster careful, well-reasoned decisions which give appropriate consideration to environmental values. There can be no doubt that an abundance of information has been provided in this proceeding. Pursuant to 42 USC § 4332(2)(c) and 18 CFR § 280, 282, the Staffs of the Federal Power Commission and Department of the Interior have written detailed, lengthy environmental impact statements assessing the "worst case" environmental risks of all 3 proposed routes, in addition to numerous alternatives. A summary of the overview sections of these statements is set out in Appendix F. Moreover, the applicants have submitted environmental reports of their respective routes. Arctic Gas, in particular, has supported extensive research, over a period of 5 years or more, to obtain the data necessary to evaluate the impact of its project. In many circumstances, this research has significantly advanced the state of scientific knowledge. Finally, voluminous evidence covering a wide range of environmental disciplines was submitted by numerous witnesses who were subject to extensive cross-examination. Of course, more information about the affected ecosystems will be available as on-going studies are completed. However, it can be confidently stated that seldom has a decision-making body been favored with so substantial a body of salient information upon which to draw in reaching a decision.

Once the necessary environmental information is made available to the Presiding Judge, it is incumbent upon him to give "good faith consideration" to the material and undertake a "rather finely tuned and systematic balancing analysis" Calvert Cliffs Coordinating Committee v. AEC, 449 F. 2d 1109, 1113 (D.C. Cir. 1971) cert. denied 404 U.S. 942 (1972). NEPA commands that agencies consider environmental issues just as they consider other matters within their mandates. This case-by-case analysis requires an evaluation of environmental factors as well as economic and technical ones. The courts have recognized, as explained by Judge Wright, that this is a flexible policy, "which may not require particular substantive results in particular problematic instances," id, at 1112. 1/

1/ These flexible substantive policy requirements were contrasted to the inflexible, strict standard of compliance applicable to NEPA's "action-forcing" procedures of 42 USC § 4332(2)(c).

There has been no judicial requirement that this balancing analysis should proceed in any fixed manner. It appears that a common-sense notion of weighing public interest "costs" and "benefits" is implied. Indeed, Calvert Cliffs, supra, did not indicate that NEPA's substantive policy requires anything more than equal treatment among competing national priorities. This is the path by which this decision will proceed. The potential environmental impacts of the various proposals will be identified, and possible mitigating factors explored. In the final analysis, the unavoidable environmental impacts will be assessed along with cost, geotechnic feasibility, financibility, the need for additional gas supplies and those other elements entering into any determination of the public interest. Throughout, the goal stated in Calvert Cliffs will be borne in mind: "The point of the individualized balancing analysis /mandated by NEPA/ is to assure . . . that the optimally beneficial action is finally taken " id., at 1114.

Substantial evidence was also submitted by the principal parties on the effects of the projects on the Canadian environment. The most significant potential environmental problems concern the proposed cross-Delta amendment of the Canadian Arctic Gas system. The extent to which NEPA applies to projects wholly contained within the boundaries of another sovereign state (i.e., Canada) is unclear. No court has yet ruled directly on the applicability of § 102(2)(c) to the international activities of federal agencies.1/ See generally, Note, "The Extra Territorial Scope of NEPA's Environmental Impact Statement," 74 Mich. L. Rev. 349 (1975). There is no need to resolve this legal issue in the present case, for it is clear that the environmental impacts on Canada should be analyzed and weighed for reasons quite apart from the possible extra-territorial imperatives of NEPA. First, the Presiding Judge has an obligation, especially in a closely contested comparative hearing, to assess all the relevant aspects of the several proposed projects in order to certificate a system that will best serve the public convenience and necessity. Clearly, environmental

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1/ In Sierra Club v. Coleman, 405 F. Supp. 53 (D.D.C. 1975), the court held that an environmental impact assessment prepared by the Federal Highway Administration for the construction of the "Darien Gap Highway" in Panama and Columbia was inadequate, under NEPA. However, in granting the injunction, the court did not discuss whether NEPA applies to the extraterritorial activities of federal agencies because the defendants did not claim that an environmental impact statement was not required.

On September 24, 1976, the Council on Environmental Quality issued a "Memorandum on the Application of the EIS Requirement to Environmental Impacts Abroad of Major Federal Actions." In it, CEQ advises that NEPA requires analyses and disclosure of significant impacts of federal actions on the environment of the countries.

impact, either within or outside the boundaries of the United States, is one of the factors that must be balanced and compared. Cf. Juarez Gas Company, S.A. v. F.P.C., 375 F. 2d 595 (D.C. Cir. 1967), an export license proceeding, where the court held that circumstances existing in Mexico were relevant to considerations of public convenience and necessity. Second, environmental impacts on Canada must be evaluated to the extent that they might affect ultimate Canadian approval of the project. Third, reliability of service of the Canadian segment of the system must be evaluated, and factors affecting reliability are often interrelated with environmental considerations. Finally, it is clear that NEPA applies to the extent that the Canadian project impinges on the environment of the United States. This is especially relevant in the cross-Delta analysis, since migratory waterfowl affected in the Mackenzie Delta spend a substantial part of the life cycle within the United States.

While Canadian environmental impacts will be considered, it must be remembered that these concerns are also being assessed by Canadian tribunals. Both the NEB and the Mackenzie Valley Pipeline Inquiry (Berger Hearings) are considering the environmental effects of the proposed right-of-way and pipeline project in Canada. They are directly responsible for impacts local to Canada, and they have the ultimate authority to deny, license, or impose conditions on the construction of the pipeline. Thus, in instances where this record suggests that conditions be imposed on Canadian construction, no conditions will be entered on the assumption that the Canadians will do so before final administrative action of this agency.

B. Principal Issues and Methodology

There are three important and controversial "physical" environmental issues in this proceeding affecting Alaska: the Arctic Gas proposal to construct and operate a pipeline across the Arctic National Wildlife Range and El Paso's proposal to both (1) cut across the Chugach National Forest and (2) establish an industrial marine facility in Prince William Sound. On the broader scale, there is only one key "physical" environmental issue: a comparison of the environmental impact of building a project to transport only U.S. gas as against a project to transport both U.S. and Canadian gas. The environmental effect of having to build two separate transportation systems, El Paso and Maple Leaf or Alcan-Maple Leaf must be weighed as against the overall environmental impact of building only one.

On the more general side, the environmental considerations also include a determination of the socio-economic impacts on Alaska, the United States and Canada. 1/ The principal issue here is not only an assessment of those impacts which may occur, particularly to Alaska, but how much weight should be given to these factors in determining which project to certificate. The complexity of the issues marshalled for consideration under this rather innocuous heading is awesome: the net national benefit of these projects to the United States' economy for the next 25 years, the impact upon native Alaskan communities which have just gained an independent economic base, the synergistic impacts, if any, on the State of Alaska, the effect upon short- and long-term employment as well as the cost to the State of possible further perpetuation of the boom-bust cycle, projections of future Alaskan demography, industry, taxes, state services, etc., and how all of these relate to the literally billions of dollars which the State will reap from its oil and natural gas royalties and severance taxes regardless of the gas pipeline project approved.

At the outset it must be understood that none of the three pipelines can be built without some adverse environmental impact, and any reasonable analysis must begin first with an appreciation of how each project would independently impact upon the environment and only then with a comparison of the projects to each other. In addition, the nature of impact is important because a totally disruptive short-term impact may have no long-term effect. On the other hand, what appears at first blush as a minor short-term impact could have long-term impacts which are totally unacceptable. Each project therefore is analyzed on the basis of both its short- and long-term impacts upon the environment.

No useful purpose would be served by any attempt to give a detailed summary of that environmental material contained in the evidence of the parties and in the environmental impact statements of the Department of Interior (DOI) or the Commission Staff. The applications and evidentiary material on the environment is massive. Arctic Gas alone submitted, for example, a superb 34-volume Biological Report Series of books and book of component environmental overlay maps for its proposed route (AA-AA) as part of its initial backup material for its environmental presentation. The Department of Interior's EIS, large portions of which were adopted by the Commission's environmental staff, comprises eleven volumes weighing about 30 pounds, and the Staff's Final Environmental Statement is six volumes, which adopt in turn massive portions of its earlier three-volume draft statement. This record is literally awash with excellent material relating to every aspect of the environment. As stated above, a summary of the environmental impact statements, showing primarily the impacts under the worst possible circumstances, is contained in Appendix F hereto.

1/ Trinity Episcopal v. Romney, 523 F. 2d 88(9th Cir. 1975), and City of Davis v. Coleman, 521 F. 2d 661 (9th Cir. 1975).

The routes proposed all traverse many areas where there would be only a limited effect upon the environment, either short - or long-term, and no effort will be made to discuss the impact which might occur except in those areas which are particularly sensitive. Similarly, some socio-economic impacts are not so significant as to merit separate discussion. This is not to say that these impacts have not been considered. Rather, it is a recognition that the evidence of record shows that in many areas, even when environmental damage cannot be avoided, for the most part it can be readily mitigated and will not result in such long-term effect that it must be independently weighed and evaluated. Examples of these areas are most stream crossings in the lower 48 states.

It is also assumed that those mitigative measures adopted by the applicants at the hearing, on brief, or in policy statements will be in effect. Moreover, it can be expected that the respective federal, state and local licensing authorities will have a substantial voice as to mitigative environmental activities (such as site-specific avoidance of sensitive areas or timing of construction). It is further expected that relatively minor realignments or mitigative measures will occur to cure localized events. A discussion of each applicant's route and viable alternate routes from an environmental point of view will be made, therefore, only as to those areas where the environmental effect is significant or the parties have argued it is significant.

Much of the discussion on the environment, moreover, appears as parts of discussions in this decision of either construction proposals or plant siting. Water withdrawal techniques, for example, must be considered as part of the snow road construction discussion, as well as their effect upon the environment--i.e., fish. Similarly, LNG plant designs proposing that water which has gained heat from its use in cooling the natural gas be returned to Prince William Sound must be considered on both technical and environmental grounds. Where possible, these discussions have been cross-indexed.

C. Arguments of the Parties

Environmental briefs were filed by each applicant setting out its own application, the environmental impact perceived by it as caused by its proposal, and the mitigation measures it will undertake to avoid environmental damages. Answering briefs were filed by each applicant, the Commission Staff, the Conservation Intervenors, and the State of Alaska. Reply briefs were filed by each of the applicants and the Conservation Intervenors. 1/ Other parties, including the States of Wisconsin, Utah, and California, discussed environmental impact in their Position Briefs. These environmental briefs total in excess of 500 pages, and the principal arguments of the parties joining the principal issues are summarized below. 2/ No separate summary has been made of applicants' opening briefs, since the prime issues are easily discernible from the summary of the answering briefs; neither is a general summary warranted of the rebuttal briefs, although some arguments made therein have been included.

El Paso, Alcan, the State of Alaska, and the Conservation Intervenors all argue against Arctic Gas' proposal to cross the Wildlife Range. Starting with the position of the Conservation Intervenors, their arguments are essentially broken down into the aesthetic philosophy and mystique of preservation of wilderness ideals on the one hand, and, on the other, an assessment of Arctic Gas' probability of succeeding with its construction plans without significantly affecting the environment. The philosophical arguments are couched in absolutes which appear tautological: any construction will defile the virgin territory and the virgin territory is defiled by any construction. Starting with the premise that the existing Wildlife Range represents an ecosystem unique in the total coastal plain of Northern Alaska and it is the only area not already despoiled

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1/ Arctic Gas violated both the direction of the Presiding Judge and the spirit of the page limitation on the Rebuttal Brief by filing an 86-page document. In the usual case, such a breach of briefing schedule and rules would require rejection of the document.

2/ Given the briefing methodology employed on the environmental briefs, the initial briefs represent a marshalling of the proposal and the supporting evidence only of that proposal. It is only in the answering brief where the key issues dividing the parties are joined. In fact, since few of the arguments were any big secret, most were obliquely addressed in the initial briefs.

or committed to possible development of some sort, they argue that it should be accorded wilderness status by this agency or at least not invaded until Congress has acted on recommendations that it be accorded such status. A corollary argument is that the enabling order establishing the range, Public Land Order 2214, 25 Fed. Reg. 12598 (1960), specifically states as its purpose the "...preserving of unique wildlife, wilderness and recreational values" and that the range is, in fact, being managed by the Wildlife Service as a wilderness. The existing and long-term human activity in the area is dismissed as de minimis, restricted to fringe areas, irrelevant, and in any event not inconsistent with the total concept of wilderness they espouse for the entire area.

Turning to Arctic Gas' construction plans, they view all construction within the area as a violation of the wilderness concept and to be avoided at all costs. Turning the coin, they argue that if construction should occur, the very fact of construction would preclude inclusion of that portion of the range as a part of the wilderness--again apparently a definitional argument. About 15% of the area, they aver, would be affected, and exclusion of this strip stretching across to the coast and "deep into the calving ground of the Porcupine caribou herd" would be required if Congress subsequently declared the Wildlife Range a Wilderness. As a part of this argument, Arctic Gas is depicted, in the Conservation Brief, as having a "voracious appetite for a major part of the coastal plain" (Br. p. 9). As a last argument on this issue, and after an extensive review of those procedures used to review and recommend Congressional approval of wilderness areas by statute, they strenuously assert that as a matter of law the status quo must be maintained until evaluation of the area can be "completed" under the Wilderness Act and Congress should choose to act, citing Parker v. United States 448 F.2d 793 (10th Cir. 1971) cert. den. 405 U.S. 989 (1972) and Minnesota PIRG v. Butz, 358 F. Supp 584 (D. Minn. 1973), aff'd 498 F.2d 1314 (8th cir. 1974).

Addressing the Arctic Gas construction program, as previously stated, they argue that the very proposal is inconsistent and incompatible with wilderness values. Numerous writers are quoted as to what are wilderness values and record citations given as to how the construction plan will impact animals, encourage increased development, and destroy the aesthetics of the range. Arctic Gas' construction plan and and planned mitigative steps to ensure limited environmental impact are criticized as overoptimistic and unrealistic. Moreover, since the environment is so delicate, they argue that there is no room for the usual margin of error associated with any grandiose construction project. In comparing Alcan and El Paso, the Conservation Intervenors find both are more desirable since they utilize utility corridors and that Alcan is more desirable than El Paso since it avoids the Chugach National Forest.

El Paso and Alcan also heavily criticize Arctic Gas' proposal to cross the Wildlife Range. All but 2 pages of El Paso's 65-page Answering Brief and all but 7 pages of Alcan's 63-page Answering Brief are directed against Arctic Gas.

El Paso's general position, which essentially is also Alcan's, is stated as follows:

> "We shall show in this brief to the satisfaction of any reasonable mind (1) that the arctic coastal plain is a wilderness area, and specifically that the area which would be impacted by Arctic Gas is wilderness, and (2) that the issuance of rights-of-way across the Range, as requested by Arctic Gas, is incompatible with the wildlife, wilderness, and recreational purpose of the Range, and hence could not be issued under existing law. But we do not rely upon the legal argument that rights-of-way cannot be issued because Congress, in section (g) of the Alaska Natural Gas Transportation Act of 1976, has stated that it will at least consider waiving any provision of existing law upon a Presidential finding that such a waiver is necessary. We therefore argue more broadly that rights-of-way should not be issued as a matter of fundamental environmental policy."

As a preliminary argument, El Paso asserts that, under the doctrine of primary jurisdiction, the views of sister agencies must be accorded great weight by the Commission, elevates the Department of Interior's U.S. Fish and Wildlife Service to the rank of a sister agency, and then quotes the personal opinion of Director Greenwalt of that service that "...no pipeline should be built around the Arctic Wildlife Range as long as an alternate route is available and feasible." Both Alcan and El Paso heavily rely on the testimony of Dr. LeResche, Chief of Habitat Protection Service, Alaska Department of Fish and Game, who described his view of the uniqueness of the Wildlife Range and the protection he believes should be afforded the Wildlife Range.

As expected, El Paso and Alcan also assert that the Arctic plain is remote and has strong wilderness value, that the Arctic Gas alignment angles quite far inland from the coast and will disturb a new area not heretofere affected, and, in any event, that even the coast itself has not lost its wilderness value. They then argue that gas transmission facilities are incompatible with the purposes of the Wildlife Range, that gas transmission facilities were not included within that mineral exploitation contemplated by permitting issuance of mining patents, and that whatever was intended, it did not encompass or envisage any surface disturbance (El Paso Br. 16-18). Attacking Arctic Gas' theory of compatibility, they assert that Arctic Gas' own witnesses fail to consider wilderness and recreational value in finding compatibility, that no consideration should be given to other possible plans to exploit potential oil and gas reserves within the Wildlife Range, and that withdrawal of pipeline rights-of-way from that acreage designated as the Wildlife Range is not an answer, given the location of the right-of-way inland from the coast.

El Paso and Alcan also address at length the construction technique and schedule, with particular emphasis on the timing and ability to make snow roads, and the effect upon wildlife. They conclude, again as did the State of Alaska and the Conservative Intervenors, that Arctic Gas is overoptimistic, cannot meet its schedule, and that its shortfall in these areas is certain to result in significant degradation of the environment with substantial short- and long-term adverse affects on all wildlife. The short of it is that they argue that none of Arctic Gas' proposed mitigative measures will work, but even if they do, the continued activities for construction, operation, and monitoring will result in long-term, grave environmental harm. El Paso's last argument, and a recurring argument through the Alcan brief, is that further studies must be made on the environment before any conclusions can be reached that construction techniques or mitigation factors are satisfactory.

The State of Alaska argues that a gas pipeline and the Wildlife Range are _a priori_ incompatible, that the range must be protected, and that Arctic Gas' application should therefore be denied out of hand (Reb. Br. p.1). While it supports both Alcan and El Paso, assuming that El Paso's route closely follows Alyeska its preference is for El Paso. As a preliminary matter, the State attacks the qualification of Arctic Gas's environmental witnesses as being no better than the other environmental witnesses, discounts Arctic Gas' own research of routing as being of little consequence because it was that of a private corporation, and asserts that Arctic Gas is entitled to no special consideration in bringing natural gas to market. 1/ The State also takes the position that the range is unique and has wilderness values, that the history of the range is unimportant since only what has occurred since the range was created which should be weighed--i.e., in creating the range, the creators knew of its imperfection and sought to preserve extant wilderness values. It argues that the impact of man's incursions have now healed (Br p.9).

The State basically believes that Arctic Gas is not only too optimistic about its ability to construct and operate an environmentally acceptable pipeline, but that Arctic Gas has ignored the consequences of delays in construction and will be under pressure to take environmentally unsound shortcuts to catch up. Thus, reviewing Arctic Gas' construction plan skeptically, it asserts that construction difficulties in sensitive areas such as the Arctic tundra create the certainty for even greater damage and that there is a near certainty of delay. The State ends up with the proposition that all claims of Arctic Gas that it will be able to construct its line expeditiously and in conformance with environmental standards be "discounted" and that the only criterion be the preservation of "...the environment which is most susceptible to serious and lasting damage if schedules slip" (Br. p. 11). The possible long-term effect upon the Porcupine caribou herd and summering birds and the aesthetic visual problem of snow roads, it argues, bolsters its position that the Arctic Gas proposal is unacceptable.

Placing great faith in the corridor concept, the State belittles Arctic Gas' theory of both adverse incremental and synergistic effects of corridor construction and presses for its idea of close alignment of the El Paso route next to Alyeska. From its own assumption that El Paso's realignment alternative is environmentally superior to El Paso's original design, and adopting the El Paso and Alcan support in the initial briefs of use of the Alyeska right-of-way, it argues the general environmental and aesthetic merits of the corridor proposal.

1/ This argument is repeated in the conclusion of the brief. The State apparently failed to perceive Arctic Gas' argument, which is that Arctic Gas can deliver more Btu's of non-polluting natural gas to the lower 48 states than its competition.

In comparing the Chugach National Forest to the Wildlife Range, the State distinguishes the establishing proclamations and avers that, unlike the Wildlife Range, wilderness values are not included in the 1907 statement of President Roosevelt establishing the forest. The State argues that the intention of including the term "wilderness values" in the 1960 Wildlife Range withdrawals was to create a true wilderness area and goes so far as to argue that it explains the failure of the Secretary of the Interior to later seek its inclusion in the National Wilderness Preservation System (16 USC 1132(c)).

Regardless of the pipeline chosen, the State seeks imposition of conditions giving the State substantial authority and responsibility, along with federal officials, to supervise and monitor construction and operations.

Arctic Gas attacks both El Paso and Alcan, aiming most of its criticism at the "corridor concept" and the El Paso proposal to locate its LNG plant in a seismically active area which is environmentally undisturbed. Its basic position is that the Alyeska right-of-way route was not established as a utility corridor, is environmentally unsuitable for burial of a chilled gas pipeline, would result in the multiplicity of other natural gas lines since it is not positioned to economically attach other prospective field supplies, will result in the building of a separate and independent line in Canada, and will result in the consumption of more energy for transportation than the route proposed by Arctic Gas. Arctic Gas vigorously asserts that there are no proven environmental benefits shown on this record for bunching energy delivery systems. It specifically attacks both El Paso and Alcan as having accomplished minimal environmental investigation and planning and asserts that neither of them has scientific basis generally, or at the site-specific level, to evaluate impact on the environment resulting from their proposed routes. Neither El Paso nor Alcan, it argues, will be able to make any extensive use of Alyeska geotechnical or environmental information, and both will have to perform substantial de novo studies of the environment prior to final design which will add years to complete their projects.

The major thrust of Arctic Gas' argument is the recurrent theme that its project is based upon extensive and thorough research of eminent scientists carried out over a number of years. Its position, unlike either El Paso's or Alcan's, is not solely to limit the weight accorded its competitors' scientific endeavors but to show on a comparative basis the superiority of its own research when compared to either the lack of or limited research of the others. Specifically, it sets out in its brief those transcript references which it believes demonstrate El Paso's and Alcan's inability to begin the site-specific alignment of an environmentally acceptable pipeline, as against the minimal additional work required to actually build Arctic Gas' line (Ans. Br. 31-35). As to Alcan's Canadian applications, it argues that they are so deficient, from the description given here, that there is no way it can envisage that the Canadian authorities could approve the applications on environmental grounds.

The Commission Staff, after (1) supporting its own Fairbanks alternative as environmentally best and (2) asserting that approval of any of the applications will result in substantial environmental impacts, chooses the Arctic Gas proposal as the least undesirable application, then Alcan, and then El Paso. Its prime arguments relegate El Paso to third place but still environmentally acceptable (with implementation of appropriate mitigative measures) because of the "environmentally dangerous" LNG facilities in both Alaska and California, unsound pipeline route through the pristine Chugach National Forest, tanker routes through sensitive fisheries, heated effluent discharges in Prince William Sound, and incursion of industry into otherwise non-developed Alaskan areas. In its view, Alcan's inability to carry projected volumes of other Alaskan gas as distinct from the initial Prudhoe volumes without another round of construction is seen to be an overwhelming negative aspect. Since Staff views both El Paso's and Alcan's proposals in the context of the need for an additional pipeline to move Delta gas to Canadian markets, it finds that the total combined proposed construction impacts of both pipeline systems (El Paso - Maple Leaf and Alcan - Maple Leaf) render them less desirable. Furthermore, Staff asserts that neither El Paso nor Alcan has done adequate environmental studies or preparation, and it particularly criticizes El Paso's lack of (1) seismic, (2) LNG site geological, (3) general biological, and (4) treated heated effluent investigation of possible adverse impacts at Gravina Point.

Its support of Arctic Gas can best be described as picking the lesser of the evils.[1] Staff does not accept Arctic Gas' more optimistic claims of its ability to (1) construct and maintain its pipeline without environmental degradation, (2) properly effect all of the proposed mitigative measures, including revegetation, (3) fully monitor its construction so as to avoid Alyeska's mistakes, and (4) avoid some further degradation of the Wildlife Range's wilderness values. After having set forth this evaluation, Staff then opines that unless all hydrocarbon

1/ This comparison is only on the environment. Overall, it considers Arctic Gas vastly superior (Position Brief).

exploration and development in the Wildlife Range is prohibited, there will be future development within the range and no reason appears for precluding a gas transmission pipeline as inconsistent with the range. As previously stated, while faulting Arctic Gas for ignoring the probable environmental degradation of the Wildlife Range and its unbroken continuum of Arctic ecosystems, it grudgingly admits that substantial effective work and effort has gone into both the design and operation, that for the most part it will be successful, and that it should be certificated. Detailed proposed conditions applicable generally or specifically to each applicant are attached as an appendix to Staff's brief. 1/

D. Arctic Gas

1. Arctic National Wildlife Range

(a) Description

The Arctic National Wildlife Range was created in 1960 by a Public Land Order issued by the Secretary of the Interior (P.L.O. 2214; 25 Fed. Reg. 12598, 1960; Tr. 234/40,710). Its 14,000 square miles is 15% of the roughly 90,000-square mile North Slope Borough (county) which is the political subdivision encompassing the North Slope of Alaska from the Bering Sea to the United States-Canadian Border (ST-26, p. 68 attached hereto at page 204). Situated in the northeast corner of the State of Alaska (itself about 590,000 square miles), it extends 150 miles south from the Beaufort Sea across the Brooks Mountain Range and 133 miles west from the U.S.-Canadian border to the Canning River --an area larger than that of nine individual states and about the size of Maryland and Connecticut combined. As presently constituted, the Wildlife Range embraces diverse habitat including coastal lagoons, barrier beaches, treeless tundra and thaw lakes in the coastal plain (30%), the foothills of the Brooks Range, and the Brooks Range. Unlike the western portion of the North Slope, the coastal plain is narrower in the east, and the mountains (about 9,250 feet maximum in altitude) are only 20-30 miles from the shoreline at their closest point near the U.S.-Canadian border.

1/ See conclusion section *infra.*

The Wildlife Range is remote and isolated and has wilderness values (ST-26). The combined population of the only permanent human settlement, Kaktovik and the nearby DEW line site, is about 200. Fairbanks is 377 miles southwest. Barrow, the seat of the county government, is 177 miles northwest. Relatively few visitors, estimated at approximately 3,500 annually, if one includes the movements of those living at Barter Island and those scientists generated by this construction proposal, come into the Range. Aside from possible encouragement of a native hunting guide industry at Kaktovik and Arctic Village, 25 miles southwest of the range, its remoteness limits general access.

Arctic Gas proposes to build its pipeline across the entire Wildlife Range in a west-east direction cutting across at a point near the Canning River 30 miles from the coast and exiting at a point on the U.S.-Canadian border about 10 miles from the coast. It proposes to construct two major construction depots and five airstrips, all more fully set forth in the geotechnical and construction section of this decision, supra. As far as the Wildlife Range is concerned, the only permanent facilities that will remain after construction are the depots on Camden Bay and Demarcation Bay, compressor station sites, the airstrips, the berm over the right-of-way until it subsides, and, after the first several years if volumes are increased, three compressor stations. The total acreage which would be permanently dedicated to the pipeline in the Wildlife Range is about 2,650 acres, most of which is the right-of-way itself which will be revegetated.

(b) Public Land Order 1/

The Public Land Order establishing the Wildlife Range provides (234/40,710):

> "For the purpose of preserving unique wildlife, wilderness and recreational values all of the hereinafter described area in northeastern Alaska, containing approximately 8,900,000 acres is hereby, subject to valid existing rights, and the provisions of any existing withdrawals, withdrawn from all forms of appropriation under the public land laws, including the mining but not the mineral leasing laws, nor disposals of materials under the Act of July 31, 1947 (61 Stat. 681; 30 U.S.C. 601-604), as amended, and reserved for use of the United States Fish and

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Footnote 1/ - see following page, infra.

Wildlife Service as the Arctic National Wildlife Range." 2/

1/ Chronology of Creation of Wildlife Range and Applicable Statutes.

1. Legislation to create the range was introduced in the Senate (S.1899) and House (H.R. 7045) in 1959. No legislation was enacted.

2. The range was created in 1960 by Public Land Order 2214 (25 Fed. Reg. 12598) by the Secretary of the Interior, pursuant to Executive Order 10355 of May 26, 1952. (234/40,710)

   (a) PLO 2214 provides that the lands shall be withdrawn from all forms of appropriation under the mining laws, but not the mineral leasing laws.

3. The National Wildlife Refuge System was created in 1966 by 16 U.S.C. §§ 668dd. This placed administration of the range within the National Wildlife Refuge System, which is now administered by the U.S. Fish and Wildlife Service.

   (a) § 668dd(d)(2) permits easements for pipelines when the Secretary determines compatible use.

   (b) § 668dd (c) provides that U.S. mining and mineral leasing laws shall continue to apply to lands within the system to the same extent that they applied prior to 1966, unless subsequently changed.

4. Mineral Leasing Laws - 30 U.S.C. 181 et seq. (1970) provide for pipeline rights-of-way and hydrocarbon removal. 30 U.S.C. 185q (1973) provides that no rights-of-way may be granted across federal lands except under this section. It has been suggested by Arctic Gas that this legislation may supersede 16 U.S.C. 668dd.

2/ In general, mining patents grants title to the surface while mineral leasing surface rights are retained by the grantor.

The key statutory questions joined by the parties center around (1) the meaning of the terms "wilderness" and "unique", and (2) the legislative intent and the discretion of the Secretary of the Interior under the statute to grant rights-of-way.

As already noted above, those opposing construction argue that not only would Arctic Gas' plan cause damage to the environment now, but, more importantly, that its initial construction is the first major invasion since the military installations were established in the 1950's, that operation and maintenance will require continued intrusions, and that the mere fact of opening the area up will have a detrimental effect on the ability to protect the area in the future and destroy this possible "crown jewel" of the future wilderness system. These latter arguments, as refined, rely on the observation that people and access always result in additional pressure on wildlife resources and that past measures to protect wildlife resources have had only limited success. As a matter of policy, their position is that any invasion, no matter how well planned and executed, is detrimental and should be denied. Alaskan Arctic does not deny that there will be an impact. Rather, it argues that there is no legal impediment to its proposal and that the impact will be small, of limited duration, and not disruptive of even a small area, much less the 14,000 square miles making up the range.

(c) General

An indication of the complexity and inevitable subjectivity of the environmental appreciations involved is the fact that each of the three principal parties viewing itself as having a duty to protect the public interest and natural environment suggest that a different route is environmentally superior. The Conservation Intervenors favor Alcan; the State of Alaska prefers El Paso; and the FPC Staff, based on its own and the DOI staff analysis, recommends Arctic Gas.

Considerations as to the future of the Wildlife Range have been the subject of intensive evidentiary showings by all interested parties. Well it should be, for its almost 14,000 square miles represents a part of a large ecosystem, some of which has not been substantially despoiled by man. Its protection, therefore, from significant degradation is important, and this consideration has been in the minds of not only the environmental groups but also the State of Alaska, Alaskan Arctic, the DOI, the FPC, and the Presiding Judge. The discussion of the impact on the Wildlife Range perforce starts with the postulate that the range must be protected to the extent consistent with its purpose and that any findings that the public convenience and necessity require construction through it should be subject to stringent conditions designed to minimize both short- and long-term impacts.

As an overview, several preliminary observations are required. One of the more difficult aspects of treating the question of what the environmental impact upon the Wildlife Range would be if the Arctic Gas proposal were certificated is that many of the witnesses had strong prejudices that the area should be left inviolate. An example was Mr. Bromley who appeared for Alcan. He authoritatively spoke of the greater effect upon mammals that would be caused by Arctic Gas construction than by Alcan, but cross-examination revealed almost no independent studies by him or specific knowledge of how mammals in the Wildlife Range would be affected. He had a clear desire to give effect to his own wish to protect the Wildlife Range (205/35,248). 1/ There can be no question that Dr. LeResche's and Dr. Greenwalt's views were in large measure dictated by their personal commitment to protect and nurture wildlife and wilderness. If they did not have that perception it is inconceivable they would hold their positions.

There is also the inference created by the parties opposing transit that those who differ with the naturalist's view of the Wildlife Range are insensitive to wildlife values. Creeping through the briefs, for example, is the argument that if Arctic Gas or the eminent scientists it hired do not agree with the assessment that grave injury must occur to the Wildlife Range's wilderness quality, it is because of Arctic Gas' willingness to "sacrifice" the range and the scientists' desire to please their employer (Conserv. Rebuttal Br. 12). El Paso argues on brief that they are Canadian (El Paso Env. Br. 19). 2/ Those that

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1/ In fairness to Mr. Bromley, he had spoken to many people and was clearly influenced by them. The point is that he had no first-hand knowledge but was willing to make sweeping generalizations consistent with preconceived ideas.

2/ Interestingly, when distinguished Canadian biologists, like Dr. Banfield or Dr. Gunn, agree with El Paso, they are "distinguished and eminent" (Env. Reply Br. 19).

may disagree with the wilderness values the opponents espouse, either the need to protect them or the need to protect them at the level suggested, are lumped together as lacking an appropriate appreciation of wilderness values or of how U. S. citizens might view them. 1/ This culminates in the Conservation Intervenor's argument that the only issue of importance to decide is that of the Wildlife Range, dismissing in a few paragraphs all other issues as being a wash and almost de minimus in comparison to the importance they place on this issue alone. This is simply not true, and consideration of the Wildlife Range and the protection of its wilderness values is just one of many issues to be considered in this proceeding.

The role of Alaska in these proceedings on physical environmental matters has often been difficult to assess. The State, of course, is keenly interested in economic development of industry, and this takes a number of interesting forms: desire for an 800-mile, trans-Alaska pipeline to supply cheap energy to the interior, liquid removal plants in the State rather than at pipeline termini in Canada or in the south 48, and possible industrialization of the Fairbanks and Prince William Sound area including, at the latter, marine terminals and hydrocarbon feedstock-based industrial plants. From an environmental point of view, each of these activities will have a far greater impact upon the State and its citizens' perspective of environmental impact than any activity in the Wildlife Range. The State position on environmental grounds clearly has been influenced by these economic considerations. The simple fact is that the State wants industry in the State, has supported the El Paso application on economic grounds, wants that industry in Prince William Sound, and has bargained with the producers and prospective pipeline purchasers of its royalty gas with tie-in considerations to supply energy for that industry.

1/ One need not go far in the briefs for an example that the key arguments are colored by the perception of the individual. Alcan states that (Alcan Env. R. Br. 14):

> ...Second, the whaling activities of the 19th century left no visible marks on the Arctic Wildlife Range, other than a very few abandoned cabins.

It is ironic that the absence of musk oxen, which were wiped out by the whalers, are not part of Alcan's "visual" spectrum in the same way that the herd of caribou still there is.

The State thus opposed the Commission's Staff proposal to site the LNG terminal at Cape Starichkof, although with less hard evidence it insisted that El Paso realign its pipeline.

It is not strange, therefore, that Dr. LeResche's opinion was not sought by the other state planners as to the wilderness value of the Chugach Forest and whether the forest should be protected (140/22,488). Neither Alaskan Arctic nor Alcan will provide to the same degree the tax base and most of the other lagniappes supplied by El Paso. (See socio-economic section infra.) Even if one were to view only superficially the environmental record and briefs, the manifold interests of the State make it more an advocate on economic grounds than a concerned party merely seeking to protect its environmental heritage. 1/

The attitude of the Conservation Intervenors also requires comment. Had they not had a cause celebre issue on the Wildlife Range, they would have opposed more vigorously El Paso's proposed entry to Gravina Point through the virtually undisturbed and wilderness area of the Chugach National Forest. 2/ While

1/ One of the more amusing aspects of Alaska's brief is that while claiming the right for its citizens to pretty near dictate a pipeline choice to the U. S., it lambasts the attempt of the citizens of the City of Kaktovik, which perches on the Wildlife Range, to have their views considered (Br. p. 8). It is not repugnant to this writer to give weight to the views of the people physically affected. In fact, this is only one consideration in reaching this decision, and both views have been given full consideration.

2/ There is less visible evidence of man's presence in the Chugach than along the coast of the North Slope and the Wildlife Range. There is simply no way to avoid the comparison that the building of a road and pipeline through the Chugach National Forest is (1) analogous in almost every respect to building a pipeline through the coastal plain; (2) taken by itself could be more detrimental in both short- and long-term impact upon the environment; and (3) that mitigative measures in revegetation and restoring mountain cuts, from the visual and aesthetic point of view, may be less successful than mitigative measures on the North Slope. Certainly such construction will be visible to more people and will impact an area more susceptible to future compatible recreational use than the Arctic North Slope with its short season and remoteness.

opposing this invasion, their opposition is quite muted and lacking inferences that anyone seeking such an invasion is voracious or insensitive to wildlife and wilderness values. From the view of a relatively unimpacted area of both vigorous and spectacular scenic beauty, the mountainous area east of Valdez and Cordova exceeds that of the North Slope. It is recognized that, like Dr. LeResche, these intervenors were confronted with a choice between perceived evils. 1/ But a choice between perceived evils hardly justifies the complete disparity between relatively similar comparisons and the different treatment accorded those that might intrude.

Additionally, not one word in the Conservation Intervenors' Brief is even addressed to the environmental consequences of spreading industry through the generally unblemished Alaskan countryside. Given the vastness of the State, the limited number of people, the general remoteness, and the harsh nature of its climate, much of the State is developed -- or despoiled if one should choose to equate the two -- for the most part only around limited highways, along some rivers, and on the coasts. Cheap energy in the interior suggests development of a type and scale not heretofore contemplated and includes suggestions by the State, for example, for possible smelting operations near Mount McKinley National Park and a large hydrocarbon-based industry on Prince William Sound. As Mr. Hickock testified for Alcan, albeit suggesting a more coastally oriented route, a "clean, quick and dirty" construction "along the Arctic Coast is better than a long-time impact of people on other places" (206/35,309).

One argument that the Presiding Judge has found particularly unacceptable in the Conservation Intervenors' Brief is the suggestion that Arctic Gas' knowledge of the environmental effects along its proposed route, based on independent site-specific research, is still woefully deficient, while it supports the Alcan proposal which from an environmental point of view is based in large measure on a literature search. Regardless of how little information may or may not have been available when Arctic Gas started its project, the research effort it has made is impressive,

1/ Dr. LeResche stated that while the Chugach was a wilderness, it was not appropriately includable within the Wilderness Act because then the Wildlife Range might be crossed (140/22,489).

and the amount of particular and specific knowledge it now has of the fauna and flora in the far north exceeds that held by its competitors on either a general or site-specific basis along their routes. This is particularly true with respect to Alcan. The quality of work of those knowledgeable and perceptive witnesses Arctic Gas used to make this record has been attacked basically only on the grounds that more is better - a truism in most scientific work and even more true in the Arctic. 1/ But there is more than sufficient information on those critical areas affecting wildlife and the Arctic ecosystem to make informed and rational judgments. Studies of most species, some representing years of research, go to the heart of the issues and are neither merely a "catalog of environmental fact" nor a "barrage" of environmental minutiae (Conservation Rebuttal Br. 8).

The suggestion that the environmental evidence adduced by the parties and the impact statements submitted by DOI and Staff are comprehensible solely to the "cognoscenti" and not at all suitable for use by the ultimate decisionmaker is rejected. The DOI-FEIS, in fact, has an overview volume. Both DOI and the Staff's material have more than ample summaries and were supported by knowledgeable witnesses who took specific positions. No one, including the Conservation Intervenors, had any trouble determining how and on what basis critical decisions were made.

Second, the Alaskan Wildlife Range is not legally a "wilderness area" under the Wilderness Act, and there is no impediment in intruding upon it because of an existing legal regimen. Its designation as a "range" does not legally prohibit transit of a natural gas pipeline, and acknowledgment of its value to wildlife, remoteness, and wilderness values does not make it legally a wilderness area, automatically prohibiting such access. As discussed below, its lack of such designation, however, does not limit the need to protect it. (See infra.)

1/ The State's suggestion that the views of these scientists are tainted because they are paid by a corporation rather than a person speaking solely for the public interest is refuted by the entire record, which is a testament to their integrity individually and collectively. Similarly, the views of those scientists hired by El Paso and Alcan are clearly their views and not those of a paymaster. Alcan's attack on Dr. Banfield (Rebuttal Br. p. 21) highlights more of Alcan's prejudice than Dr. Banfield's lack of expertise.

Third, the Wildlife Range, while remote, is not unimpacted by man. To begin with, for example, whalers and other hunting pressure before the turn of the century totally wiped out the native musk ox herds (AA-Q, Chapters III, section G. p. 36); various sites have been used for military purposes (Barter Island, Camden Bay, Demarcation Bay; Exhibit AA-41 amended); exploration for hydrocarbons onshore and off the coast in the Beaufort Sea is proceeding (Exxon and Dome Petroleum); all sorts of studies are made almost continuously which bring substantial air traffic; and Alaska is encouraging guided hunting trips into the range as a part of its program to aid native income (Staff FEIS). Thus, despite its isolation, man does and has used the area for a number of years and will continue to do so regardless of whether a transit line is approved here. These are the facts, whether one characterizes these uses as nibbling at the coastline or a massive invasion by a transportation corridor. They will be explored below.

It is found below that the Arctic National Wildlife Range is not a "wilderness" under the Wilderness Preservation Act, that the construction of the natural gas pipeline through it in the manner proposed and subject to the mitigative conditions imposed is compatible with the purposes of the reservation as a wildlife range with wilderness values, and that the designation under the P.L.O. does not act as a bar at law or fact to the Arctic Gas project.

d. Wilderness and Uniqueness

Any discussion of the environment, and particularly the Wildlife Range, must begin with the understanding that a segment of the population believes that any intrusion of man in an otherwise undeveloped area will have negative environmental effects on the balance of life or existing aesthetic values. If one assumes that any change in what nature has created represents a degradation, any intrusion will, by definition, have negative impacts. 1/ Badlands in the Dakotas are to be preserved, in their erosive condition, at the same level as forests in the Alaskan panhandle or tundra in the far north. There is a subjective appreciation of values that also comes into play - ranging from the value of preserving an endangered species to the enhanced value to some people to either camp or hunt in relatively isolated areas, and the individual's own balancing

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1/ There are views to the contrary. There are signs in Ft. Tryon Park in New York City which read: "Let no man say and say it to your shame, that all was beauty here until you came."

of the needs of the general public and his bèlief as to what is acceptable intrusion.

The wilderness quality and uniqueness espoused by those opposing transit across the Wildlife Range is difficult to define. It turns in large part on an aesthetic appreciation and, in fact, that appreciation is quite distinct from other impacts. For example, a gravel road through the Wildlife Range could serve a number of useful purposes such as cutting down air traffic and localizing the disturbance of birds, permitting better Wildlife Range management by the DOI staff now performing all management functions by air from Fairbanks, 375 miles away, or permitting future hydrocarbon exploration (if allowed) to be made from established roads, thus obviating substantial further construction. 1/ Additional beaded lakes on the coastal plain, a possible result of subsidences along the snow road right-of-way if revegetation is not complete, would provide additional habitat for waterfowl and possibly increase waterfowl production.

Nor is all of man's presence totally undesirable even to those arguing for purity of wilderness quality. Commercial hunting expeditions are considered consistent according to those who support it, like the State, and those who permit it, like DOI, and does not in their views affect wilderness since man's presence is not permanent. The solitary hunter's aesthetic appreciation also becomes important, even though on its face any hunting from snowmobiles with highpowered rifles must represent an interference with the natural order. Certainly a solitary hunter whose experience is heightened by hunting alone does not care for commercial hunting parties. This is not intended in any manner to detract from any aspect of hunting but only to demonstrate the sliding scale of judgments which is brought to the subject. Nor is it intended to suggest that the Wildlife Range does not have wilderness values because there is or will be hunting, but only that the values are subject to a wide range of subjective determinations.

Furthermore, just as each human being among the three billion human beings on earth is unique, so is the Wildlife Range. But, unlike the usual connotation of uniqueness which

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1/ The Conservation Intervenor's Brief recognizes this phenomenon and refers to the resurgence of white-tail kite hawks along California freeways (Br. 20, fn. 28).

to many people would embrace the remaining habitats of fauna or flora or unusual scenery on the spectacular scale (Grand Canyon, Yellowstone Geysers, Petrified Forest), the use of the word "unique" here describes a more subtle appreciation. There are no endangered animals, birds, fish or other fauna or flora in the Wildlife Range, and the same type of animals -- whether it be polar bear, caribou or arctic char -- can be found throughout the remainder of the 750 miles or so of Arctic Coastal plain. 1/ While the ecosystem at any one place is certainly distinctive, peculiar characteristics would be equally noted for each area of the North Slope, just as each human being would "define" a different man. The more subtle appreciations of uniqueness argued here, therefore, are (1) the juxtaposition of certain physical aspects of the coastal plain with the foothills and mountains of the Brooks Range, but for the most part, the same coastal plain, foothills, and mountains occur across the North Slope, and (2) that it, unlike the rest of the North Slope, is "unspoiled."

The same subjective appreciation applies to the term "unique" as to the concept of "wilderness," and the perception of what would constitute a destruction of that "uniqueness" will vary from individual to individual. Dr. A.W.F. Banfield, an Arctic Gas witness with excellent academic and practical credentials, did not personally believe the coastal area was a wilderness. Dr. LeResche, also with excellent credentials, did.

But even more importantly, the main aspect which is suggested here as "unique" by many of those pressing the point is the aesthetics, the visual aspect from the shoreline to the mountains 20-30 miles distant and the visual unspoiled nature of the range. (See Alaskan Br. p.7.) No buried pipeline will interfere with the vista from the coast to the mountains, and it is unlikely that the three compressor stations, if built, would be that much of a visual impairment. Certainly an aerial view of a man-made 15-foot wide berm with a different vegetative mat or color than the surrounding tundra would disturb some, just as the knowledge "that man is there" may

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1/ While it is highly unlikely that any endangered fauna or flora will be disturbed by El Paso's or Alcan's alignment, a finding to that effect cannot be made, since neither applicant has done site-specific biological work.

destroy the wilderness quality for some who will never see the range. 1/ But this is hardly the type of sensitivity which should have controlling weight in determining whether the application should be granted.

The seismic trails and winter trails which may have been made by bulldozers over unprotected tundra (e.g. the Hickel Highway), are definitely present elsewhere, but it is sheer nonsense to suggest that access to Arctic Gas will result in the type of degradation permitted elsewhere at times in the past. The fact is that most of the North Slope just from Barrow east is undeveloped and not spoiled except for Barrow, Prudhoe Bay and Barter Island. The big bugaboo, snow trails, are generally visible only from the air or immediately upon them if they have thermokarsted. The same argument about wilderness generally can be made of the unblemished quality of the tundra for the rest of the North Slope if one is willing to exclude Barrow from NPR No. 4, or Prudhoe Bay and the Alyeska pipeline corridor from the consideration of the total Sag River valley. 2/

What encompasses the impacted Wildlife Range, again like the definitions of "unique" and "wilderness," is essentially definitional. If there is something which is contrary to the definition, change the definition. Smack in the middle of the coastal section of the Wildlife Range is an operating active Dew Line site with multistory radar receptors, an airfield, dock, boats, etc. (AA-42). Next to it is Kaktovik. Nothing appears to rust very fast in the Arctic and, because of the permafrost, nothing, or little, is buried. 3/ And, since the

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1/ Dr. LeResche agreed that there were many places where one might not see the presence of man in Alaska but "that... is different than being aware of it and if that seems like a frivolous distinction, to me personally it is a very important distinction. (140/22,453).

2/ The hour's flight (150 miles) from Atigun Pass to Barrow was over uninhabited areas, with little or no indication of man's presence except for the ubiquitous oil barrels. It is recognized, of course, that oil exploration has and will occur over this expanse which is about the size of Indiana.

3/ From external appearances, the long-abandoned Dew Line station at Demarcation Bay visited on the official tour appeared as if the people could have walked away just a few days earlier.

terrain is flat, the debris of civilization, broken snowmobiles and beached boats, discarded appliances, etc. are visible around and about all of the houses of native villages. The wilderness aspect of the Wildlife Range is maintained by defining Barter Island and Kaktovik out. Similarly dismissed are Demarcation Bay with its beached wrecked ship, temporary native hunting and fishing villages, and the Dew Line sites. Arctic Gas cites Lewis Carroll's Humpty Dumpty who said "When I use a word, it means just what I choose it to mean--neither more nor less." Humpty Dumpty would be right at home in a number of briefs filed in this case.

e. Statutory Considerations

From a statutory point of view, there is nothing that prohibits a natural gas pipeline from being authorized to cross the Wildlife Range. 1/ The language on the face of the Public Land Order (PLO) specifically provides for issuance of permits under the Mineral Leasing Act - a totally useless verbiage if a pipeline right-of-way is excluded. What is sought is a bootstrapping from the protection of wildlife in a range to the status of wilderness as if Congress had acted and put the range within the National Wilderness Preservation System. But while the Congress can effect this change, the Commission cannot do so as a matter of law. And it would be grossly improper to suggest that Congress sought to prohibit all mineral leasing on the Wildlife Range when it amended the National Wildlife Refuge System Administration Act (NWRSAA). 2/

Nor can the Commission make findings which *de facto* would give to the Wildlife Range a status under the Wilderness Preservation Act which it does not enjoy by statute. The argument made is that the Secretary of the Interior and the Commission, acting under the Natural Gas Act, must prohibit any project which is not compatible with the purposes of the Wildlife Range, which is then defined as if under the Wilderness Act. The opposing parties argue that the Commission can only permit a gas pipeline right-of-way if it is determined"...that such uses are compatible with the purposes for which these areas are

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1/ This Wildlife Range is one of 372 administered by the Fish and Wildlife Service (181/30,112).

2/ In the Wilderness Preservation Act, Congress specifically reserved to itself the right to determine what would be included as a wilderness. 16 U.S.C. 1132 (a).

established" (NWRSAA)(688 (d)(1)(B1). Since there are wilderness qualities for which the range was established, it is argued that all commercial activities must be found not compatible.

Turning to the specific language itself, of all of the projects possible under the leasing laws, a gas pipeline would be numbered among the most innocuous. The complete section 16 U.S.C. 668dd(d)(1)(B) of the Refuge Administration Act provides: 1/

> /That the Secretary may/... permit the use of, or grant easements in, over, across, upon, through, or under any areas within the System for purposes such as but not necessarily limited to, powerlines, telephone lines, canals, ditches, pipelines, and roads, including the construction, operation, and maintenance thereof, whenever he determines that such uses are compatible with the purposes for which these areas are established.

El Paso reproduced in brief H.R. 7045, "A Bill to Authorize Establishment of the Arctic Wildlife Range, Alaska, And For Other Purposes." Passages from the legislative history, primarily before the Subcommittee on Fisheries and Wildlife of the House Committee on Merchant Marine and Fisheries, 86 Congress 1st. sess. (1959), were also reproduced, and these passages are set out in Appendix G hereto. Arctic Gas in its Answering Brief attacks El Paso as "disingenuous" and has reproduced long portions of a discussion just between Congressmen Dingell and Stevens (p. 155 of the House Hearing) and also between Congressmen Dingell and Stevens and with the then Assistant Secretary of the Interior for Fish and Wildlife, Mr. Leffler. Those sections relied upon by Arctic Gas are voluminous, but given the importance of this issue to the parties and the rather unusual argument made by El Paso on this point, are also reproduced in the appendix attached

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1/ 1973 amendments to the Mineral Leasing Act provide that a right-of-way should not be granted if inconsistent with the purposes of the reservation, 30 U.S.C. §185(b)(1).

hereto (Appendix G). 1/ First, the "legislative history" raised by El Paso and argued by the parties as standing behind the P.L.O. is misleading in that the bills introduced to the Congress were not passed and the nexus that Congress subsequently approved the language in the PLO as reflecting those meanings discussed in the introduced bills is lacking. The actual history surrounding both the aborted bill and the PLO has been set out above. Second, the so-called "legislative history" of the PLO cited by El Paso in its Reply Brief (p. 14-19) simply does not stand for the rather unusual oxymoronic El Paso proposition that Congress and the Secretary of the Interior desired to permit mineral leasing so long as the surface of the Wildlife Range was not disturbed in any manner. The impression left by El Paso is that somehow Congress intended to permit mineral leasing (translate mining or extraction without legal title to the surface) so long as no holes were dug in the dirt and no roads built or any surface conveyance used to move the mineral off the lease.

The more complete reading of the passages from the House hearing bears out what common sense already dictates. Omelets are not made from unbroken eggs, and there were no mining procedures known in 1959, whether open pit, strip, or deep mine, which suggests that Congress could include mineral leasing activity as acceptable for the Wildlife Range while intending to preclude such activity by prohibiting the only methods known

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1/ The mineral leasing section of the proposed bill reads (3(b) of H.R. 7045):

> (b) All mineral deposits in the wildlife range, of the classes and kinds subject to location, entry, and patent under the mining laws and subject to leasing under the mineral leasing laws of the United States, shall be, exclusive of the land containing them, subject to disposal under such laws. However, a patent issued for such mineral deposits shall not convey any interest in the surface of the land containing such minerals other than the right of occupation and the use of so much of the surface of the land as may be required for purposes reasonably incident to the mining or removal of such minerals under such regulations as may be issued by the Secretary of the Interior, and appropriate reservations shall be inserted in any mineral patent that may be issued hereunder for the aforesaid purposes.

then or today for accomplishing that end. Surface title lets the lessee do too much of what he pleases, and the Secretary of the Interior wanted to retain surface control. It was never argued that mining patents and mineral leases would not be issued, and if the "legislative history" is a guide, it shows that it was always intended that they would. It is unlikely, moreover, that any mineral extraction activity is as limited in its short- or long-term environmental effect as the mere grant of a pipeline right-of-way. 1/

It is also of interest that it is the State of Alaska, through its Congressmen, that was and is interested in assuring future development of the State's resources. Nowhere has the State in this case even remotely suggested that it would favor locking away all of the mineral reserves under the Wildlife Range.

Several other arguments based upon statute or case law are made by various parties opposing Arctic Gas. Since the only reason the Secretary of the Interior may not have included the Wildlife Range in his recommendation to Congress for inclusion of various areas in the Wildlife Preservation System under the 1964 statute which expired of its own terms in 1974 was the existence of native claims, the argument goes, the Commission cannot act so as to affect this area before a proper determination is made. 2/ In essence, the Conservation Intervenors are suggesting an equitable argument and they cite no case where a statute has expired and the courts have intervened to protect the res until full consideration under a new statute is afforded. But, this argument is again bootstrapping, for here Congress in the statute in question neither extended the time for inclusion nor foreclosed itself from acting in the future. Moreover, why native claims or anybody else's claims foreclose the Secretary from making recommendations to the Congress is unfathomable from this record.

1/ It is furthermore the norm for rights-of-way to be granted in wildlife ranges, and AA-119 sets out those ranges where such rights-of-way have been granted. Over 70% have such rights-of-way. Arctic Gas argues that reference here to "wilderness" is not determinative since the only common denominator of all ranges is wildlife. This is correct, but is a non sequitur since it is the inclusion of the term "wilderness" which is at issue.

2/ The Wilderness Act, 16 USCA & 1131 et seq.

As a final matter, of course, Section 8(g)(1) of the Alaskan Natural Gas Act (Appendix D) would govern in this case. This is only a make-weight conclusion, for it says no more than that if Congress and the President approve the Arctic Gas application, they will also legislate crossing the Wildlife Range, and there will be an implicit finding that the right-of-way is consistent, compatible, and in all manner in harmony with the Wildlife Range and its purposes.

The concept that the gas pipeline would be the precursor of other development of hydrocarbons on an accelerated basis may well be true. But what it omits is that a denial here will in no way lessen the need for a decision on whether hydrocarbon exploration should be permitted and in no way will lessen the pressure for granting such permits as being in the public interest. Arctic Gas, of course, does not rely upon future hydrocarbon discoveries to justify its route.

A finding has been made here that the United States faces an energy shortage, and a natural gas shortage in particular. See Nationwide Rate Case, Op. 770 (1976). It is clearly in the public interest to exploit hydrocarbon reserves, and unless Congress unequivocally prohibits such exploitation in or off the Wildlife Range, the ultimate incursion into the range for such exploitation must be considered a virtual certainty. The Commission cannot ignore that such exploitation in all likelihood will occur; and to the extent that such exploitation is likely to occur, it makes less significant the fact that Arctic Gas is the first major construction project on the eastern reaches of the North Slope since the construction of the DEW line stations. If one assumes a certainty of exploration, rather than a likelihood, the gas line construction in fact becomes a benefit from the point of lessening the environmental cost of attaching the new supply. It is recognized, of course, that each new venture would have to stand on its own and would be subject to a determination on the merits.

There are two arguments made, however, which deserve separate attention here. First, that a postponement will permit further study of the environment and possible development of techniques of construction more compatible with environmental protection, or even a slackening of need for additional hydrocarbons which would render unnecessary exploration and possible development of the Wildlife Range. Second, it is argued that the construction here traverses the entire Wildlife Range, while future development may not be as substantial. Although there is obviously more study to be done on the arctic environment and construction techniques, the proposal here by Arctic Gas represents a more than sufficient basis for knowing the consequences of man's acts and protecting against them. Several biologists, including Dr. Maxwell Britton for DOI, testified that additional work should be performed on the cross-Delta route to establish its environmental desirability as against the original Arctic Gas route which avoided the Delta (134/21, 455-21,456). But this is a far cry from finding that there is insufficient evidence. It is found from either the findings of Dr. Gunn and Dr. Banfield or the F.F. Slaney white whale study that pipeline construction is acceptable.

As far as the slackening of energy demand is concerned, every study shows that even if all conservation measures are successful, it will be mandatory for the United States to exploit its hydrocarbon energy supplies. 1/ This argument, and the damnation of the U.S. consumer's "insatiable" appetite for energy, goes nowhere. It is not in the public interest to base a decision on the hope that an existing problem will dissipate when all of the evidence says it will not. It is, of course, also true that until decisions are made to permit exploration, one does not know where the impact of the exploration or where gathering lines would be. But, reliance upon the proof of a negative--that the whole coastal part of the range may not be impacted--does not recognize the finding that the long-term impact of a buried pipeline is, of itself, minimal. It is the lack of future major leasing on parts of the coastal area which would insure little long-term effect on wildlife, wilderness or recreation values. Denying the application here would and could not insure against such development.

1/ Mr. Hickock who, as an employee of the Department of the Interior wrote P.L.O. 2274, knew of the suspected hydrocarbons under the Wildlife Range and stated that "... if it is in the United States' interest to have Prudhoe Bay, I don't see why it isn't in the United States' interest to also have the Marsh Fork anticline as energy for our people" (206/35318).

ST-26, p. 68 as modified

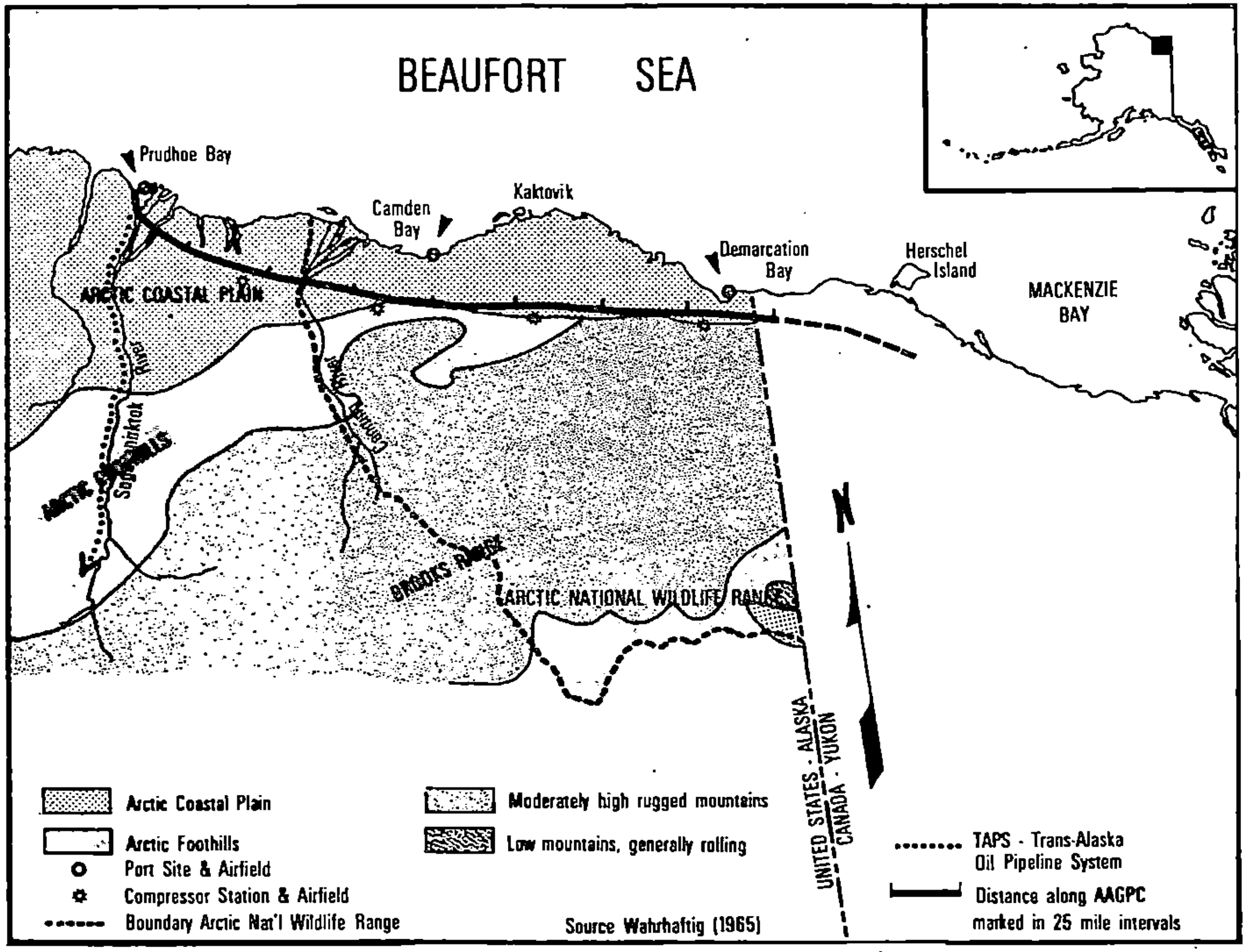

Figure 2.1.1.2-1 Physiographic divisions associated with the AAGPC pipeline system, Alaska

2. Specific Impacts

(a) Mammals

i. Caribou

There can be no question that of all mammals, the Porcupine caribou herd represents the single most important consideration. 1/ It uses the Wildlife Range. The Porcupine herd, numbering about 110,000-120,000 animals, migrates between points in the Canadian Yukon Territory on the one hand, and, on the other, the Brooks Range and North Slope of Alaska, over an area of about 120,000 square miles. 2/ The most critical part of the life cycle of a caribou herd is the time of calving and the post-calving aggregation which, for the Porcupine herd, occurs in the Camden Bay area on the Beaufort Sea sometime during the last weeks of May and the first week in June.

Arctic Gas describes the calving grounds of the Porcupine herd as follows (Int. Env. Br. 18, ft. 17):

> The calving grounds of the herd include the Arctic coastal plain and foothills from about the Babbage River in the Yukon Territory to the Katakuruk River in Alaska, an area of about 7000 to 8000 square miles. Caribou calve from May 28 through June 15, peaking around the 5th or 7th of June. Calving occurs most intensively along the foothills zone (Roseneau, 11/1900). The number of calving caribou on the coast is quite low. Caribou are quite dispersed on the calving grounds during calving /_Transcript Citation Omitted_7.

Arctic Gas' construction schedule could affect the herd in several ways. Its early summertime use of the Camden Bay site for barge unloading and as a general marshaling area could affect the calving and post-calving aggregation. Airplane overflights could affect migrating caribou during the

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1/ Reindeer are "domesticated" caribou. "Domesticated" is defined as loosely as nomadic following of a herd, as is done by some eskimos.

2/ Basically the definition of what constitutes a herd is the calving area used, so that if a substantial number of the Porcupine herd changed their calving area, this would result *ipso facto* in a "diminution" of that herd. (See Bromley, 205/35,153, and his description of the Forty Mile herd, 205/35,254.) The Porcupine herd calves at Camden Bay.

summer, but height limitation would be an effective mitigative measure. Increased hunting pressure could occur from the availability of additional airstrips and wider knowledge of more people of the presence of game and access. Additionally, if a compressor station is built at Camden Bay, there would be a permanent installation in the post-calving aggregation area. Assuming the berm over the pipeline did not subside, the caribou might use it to avoid mosquitoes.

Any discussion of the impact upon caribou herds by construction, operations and maintenance of pipelines, including intrusion on calving grounds, must come after the realization that none of these activities represents the significant factor in caribou herd viability in Alaska. Man has been systematically destroying these animals through overhunting, whether by subsistence hunting or sport, to the point where the herds may not be able to maintain population levels necessary for survival. (See e.g. Hickock 206/35,321.) The Forty Mile Alaska herd, for example, has been reduced in a short period of time from literally hundreds of thousands of animals to a size where it may be exterminated if hunting pressure is not removed. 1/ The same could well happen to the Porcupine herd, if the same hunting laws are in force, and for the State and Federal officials to sanctimoniously enter into discourses as to whether a pregnant caribou will or will not cross a one or two foot high berm, while still permitting almost indiscriminate shooting of these animals by any Alaskan along the migratory route (or any rich hunter wanting a "double shovel" set of antlers) is illogical. 2/ It is not the illegal hunter or few people who have the money and inclination to fly illegally into restricted airstrips which would hurt the herd. That concern is real, but manageable. What are not manageable are state game laws which, until

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1/ Estimates of as high as 500,000 at the turn of the century to almost 6,000-8,000 today. Testimony also suggested that splitting of the herd and natural predation may be responsible for the diminishing size of the herd (Dennis D. Bromley, 205/35,254).

2/ See Knap, "Eskimo Country: My Hunt for the Double Shovel, Quebec," Outdoor Life August, 1976 at 78. Hunting caribou for sport seems akin to hunting milk cows. Tr 18/2613.

recently, have not even addressed the problem. 1/ Only planes permit easy access, and it is sheer nonsense to argue that plane traffic could not adequately be policed if the object were to prohibit recreational hunting alone. 2/

Nor is there any significant evidence that the plans of any of the pipeline applicants will adversely disturb, in the short or long term, any of the caribou along those pipeline routes. In the words of Dr. Banfield, caribou are "stolid" animals, relatively docile and reasonably tolerant of man's presence as long as not particularly harrassed. Noise studies show reasonable tolerances and, in any event, flight pattern rules and noise reducers on compressors will relieve much, if not all, of the noise nuisance. The pipeline applicants for the most part will not be where the caribou are at the time of construction. Aside from the Camden Bay camp construction, which construction would be held in abeyance if it appeared it would interfere with post-calving aggregation, the Arctic Gas winter schedule avoids caribou completely. Similarly, there is no showing that the El Paso or Alcan routes would harm caribou or could not avoid construction in calving areas during the short portion of the year when such grounds are used.

ii. Other Mammals

The impact on polar bears by Arctic Gas' wintertime construction schedule was massaged to a fare-thee-well. The evidence shows that polar bears are essentially marine mammals inhabiting the pack ice and feeding on other animals associated with the ice pack. There is no evidence that the Beaufort Sea polar bear population extensively use dens on the land mass, and there is substantial evidence that they do not. In the one study made, even given limitation of available surveillance, only three dens were observed in the late spring by aerial reconnaissance. Kills of 5 polar bears annually by the native community at Kaktovik do not indicate great use of the Wild-

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1/ Dr. LeResche testified as to stringent caribou hunting laws (140/22,449-E). The record describes caribou subsistence hunting as being year round (ST 26-30).

2/ Of interest is that testimony of El Paso witness Dr. R. Sage Murphy, who stated that hunting pressure is easily controlled (62/9324).

life Range land areas, since polar bears are attracted to human communities and the community is not far from the sea ice. There is little likelihood of any substantial interaction with polar bears. Last, a polar bear will depart the area if disturbed, and there is little likelihood that any one would choose to stay in the way, even if he was able to do so. Nonetheless, those arguing against Alaskan Arctic claim significant probability of polar bear impact. It is found that the impact on polar bear, if at all, would be negligible.

Barren ground grizzly bears are referred to in the DOI statement as possibly greatly affected (ST-26-421), but this was not supported on cross-examination and was totally rebutted by Arctic Gas witness Ronald D. Jakimchuk (172/28,222 - 28,223). Dall sheep are only in the foothills, the 40 or so musk ox have more than enough range, winter and summer, to completely avoid pipeline construction. It is unlikely that there would be any significant effect on any of the other mammals on the North Slope. (See ST 26-421.) Some animals, like wolves, may have more to fear from "enlightened" game management programs by DOI and the State than from any pipeline construction program.

(b) Fish and Water

There are two principal environmental concerns stemming from winter construction and use of snow roads which must be discussed: water withdrawal to build snow roads basically affects both fish, and vegetation and the vegetative mat. The latter affect stability of the pipeline, a construction problem, and changes in the surface, which are largely a matter of aesthetics. This section addresses the fish and, to an extent, the aesthetics.

As has been stated in the snow road discussion, supra, the Arctic Gas plan calls for snow manufacturing as one snow "accumulation" technique. Water sources are required in order to make snow, and this presents unique problems on the eastern reaches of the North Slope where free-flowing water sources are particularly scarce in the winter and where overwintering fish may inhabit the water sources that are available. Thus, it is the environmental impact upon the fish which is at issue. Most of the discussion on the record concerning water availability focused on sources from Prudhoe Bay to the Mackenzie Delta, with particular emphasis on the 120-mile segment in eastern Alaska -- the Wildlife Range. This discussion will concentrate therefore on this geographic area. 1/ Moreover, since the principal dispute on water availability was joined by El Paso, reference is made most frequently to El Paso's arguments, even though the other parties opposing winter construction in the Wildlife Range make the same arguments. As with the discussion on snow roads, an attempt has been made to be complete.

i. Water Withdrawal

The State of Alaska claims authority under its Water Use Act for all water use on public or private lands, state or federal. Alaska Stat. 46.15.010 et seq. (Water Use Act). Under the Anadromous Fish Act, Alaskan Stat. Title 16.06.870, the authority to issue and enforce water use permits is delegated to the Department of Fish and Game. Permit stipulations include immediate cancellation if withdrawal of water threatens to damage a fishery resource. According to Alaska witness Robert LeResche, the Department of Fish and Game has experienced problems with the overuse of water during the winter on the North Slope. Problems were especially acute in the winter of 1974-1975. The type of water use envisioned by Arctic Gas is also theoretically controlled by the Water Resources Section, Alaska Division of Lands, which issues water appropriation permits pursuant to the Water Use Act. 2/

1/ The FEIS of DOI, "Canada" (ST-27), states that large quantities of water are available north of 60° latitude in Canada. Throughout much of its length, the pipeline would be near large streams having large winter flows. However, the FEIS stated that none of the streams in the Malcolm, Firth, Spring, Crow, Babbage, Walking, Blow and Fish River drainages in the Beaufort Sea region have significant water discharges. It states that the tapping of lakes or subsurface sources in this region could reduce overwintering areas.

2/ LeResche testified that the Water Resources Section has little information on water availability on the North Slope, and industry has, in the past, been allowed to appropriate waters with detrimental effects on fish. Since then, closer cooperation and scrutiny between industry and state agencies has avoided fish-kill problems.

Arctic Gas has estimated that it will need a total of 8,222,000 bbl of water for its construction from Prudhoe Bay to the west side of the Mackenzie Delta. 1/ This includes 6,000,000 bbl for snow roads, with the remainder needed for domestic use, hydrostatic testing and ditch flooding. The 6,000,000 bbl required for snow roads includes 20 miles of snow road, 30 feet wide and 9 inches deep, for each of the five spreads west of the delta. 2/ The figure also includes access roads from Camden Bay, Demarcation Bay, Komakuk and Shingle Point to the right-of-way. Arctic Gas witness G. Leslie Williams testified that this figure assumes a situation more severe, i.e., less snow fall, than any of the recorded years in Ex. Ala-15. However, the figure does not include water needed for access roads from water sources and assumes a level terrain (less than 5%), with little snow required for grading. Williams considered these insignificant omissions, considering the liberal requirement estimates (163/26,886-895). Also, the estimate assumes a 9-inch deep work pad, while Arctic Gas, on brief, suggests a 9-inch to 12-inch work pad. (See Alcan Init. Geot. Br. p. 46, which refers to the Alyeska **nonprocessed** snow pad.)

Snow manufacturing will begin in early October. Arctic Gas shows, in AA-43, App. Table 1 (p. 59), that most water for snow roads will be required in October and November, with more limited amounts needed in December. Arctic Gas anticipates using 65% of the total water required before the end of November, and so admitted on the record. 3/

ii. Water Sources (in **General**)

Generally, there are three potential sources of water on the North Slope: groundwater, flowing surface water (mountain, tundra and spring streams) and standing surface water (lakes

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1/ Alaskan Arctic's Exhibit AA-43, Water Availability Along the Proposed Arctic Gas Pipeline Route, was inadvertently not admitted in evidence. It is hereby admitted here and in the transcript corrections volume.

2/ Williams testified that for a snow road 30 feet wide and 18 inches deep, there is a need for 21,000 bbl/mile; for a work pad 90 feet wide and 9 inches deep, 32,000 bbl/mile (163/26,859-864).

3/ This has advantages and drawbacks. Larger volumes are used before the hardest part of the winter further freezes the sources, but the larger use may itself cause drawdowns of supplies more rapidly than the optimum.

and ponds). Only spring streams, certain portions of mountain streams and a few lakes are not frozen to the bed during the winter, and thus can both serve as a source of supply for snow roads and as a habitat for spawning and overwintering fish.

Mountain streams derive from springs and surface runoff. The springs are perennial and provide the only source of winter flow. Some springs enter the beds of mountain streams directly, while others originate some distance away and flow through separate channels (spring streams) before joining the mountain streams. Mountain streams in the area flow throughout their length for 4-5 months. By mid-October, surface runoff ceases, and the only flow is provided by groundwater sources. As the weather becomes colder, these areas may freeze to a large extent. The spring sources provide perennial flow only in limited quantities and areas. The date when surface flow ceases in mountain streams varies. For example, AA-43 (App. Table 4) indicates numerous mountain streams flowing through November, while EP-238 (Table 5) indicates only four mountain streams not frozen to the bed by November 7. Isolated areas in streams containing pockets of water during winter have been observed and are probably fairly common. Some are derived from artesian sources which are directly in the channels, while others may be derived from the emergence of subchannel flow. These pockets are usually difficult to locate. The Arctic Gas route crosses 19 mountain streams.

Spring streams are spring-fed tributaries of mountain streams. These are small streams, generally less than 1.5 km in length and only a few meters wide. Discharge into the stream from orifices is perennial, and total discharge for two springs studied by Arctic Gas consultants, P.C. Craig and Peter McCart, remained relatively stable during the periods of observation.

Standing water sources are most abundant in the western part of the route, becoming relatively sparse east of the Canning River. The most abundant are ponds (less than 6.6 feet deep), which freeze solid during the winter. Ice begins to form on arctic lakes in September, with ice depths normally reaching 2 feet between November 7 and November 30. Ice depths reach a maximum of 6 feet to 7 feet in late winter. McCart indicated that he expected 2 feet of ice by December 15. Thus, he concluded that large volumes of water were available from lakes up to mid-December. El Paso witnesses Dennis Ward and Richard

Furniss focused their analysis on lakes 2,000 feet or more in one dimension. They stated that 2,000 feet is the minimum size for lakes to be underlain by talik. Any lake underlain by talik is deeper than the maximum thickness of winter ice. Thus, lakes at least 2,000 feet long have been chosen for analysis because research has shown that lakes that big do not freeze to the bottom and thus must be at least 6 feet deep. They concluded that many lakes in the Coastal Plain which do not meet the 2,000-foot minimum length requirement are too shallow to serve as winter sources in late winter. This logic appears faulty. It is not the water available in late winter that is significant, but available from October to December, if early snows do not occur. Thus, to only analyze lakes over 2,000 feet would exclude smaller lakes that would have water available from October to December.

It must also be noted that it is possible to retard the development of ice on lakes by increasing the snow layer by placing snow fences on the ice in early fall.

iii. General Considerations

Since the areas of unfrozen water are limited and geographically isolated on the North Slope, these areas are important as spawning and overwintering sites for fish. They are critical to the survival of species which are dependent on them as winter habitats. Standing crops of all age classes are often high, and all age classes are often present in these waters. Moreover, northern fish are more susceptible to exploitation than those of other climates. Due to slow growth rates, they recover slowly. The dangers inherent in withdrawing water from these areas are threefold: 1) freezing eggs of spawning fish by dewatering spawning gravel; 2) de-oxygenating water of overwintering fish; 3) inducing remaining levels of water to freeze, thus killing overwintering fish.

In addition, the FEIS of the DOI, "Alaska" (ST-26,423), suggests that water withdrawals from lakes could result in an increased mineral content in the lakes. McCart deemed this threat insignificant. First, increases in mineral content are common phenomena in small lakes in the Arctic, and there is no evidence that fish or other aquatic organisms are particularly sensitive to them. Second, increases in salinity are likely to be a problem only in lakes of marginal depth. It has been recommended that such sources not be used.

The significant burden,therefore, for Arctic Gas was to identify those sources which serve as spawning and over-wintering areas for fish, and to estimate if and how water could be withdrawn from these sources without harm. This burden was complicated by the fact that different species use different overwintering habitats. Arctic char, grayling, lake trout and burbot inhabit lakes. Grayling also use streams. Ninespine sticklebacks use lakes. Arctic char use spring areas and mountain streams. Char overwinter in delta regions.

Fall spawning usually occurs in areas which do not freeze during the winter. Arctic char spawn from September 15 to November 15 in large mountain streams. Arctic char and grayling spawn in spring streams during the same time, although some spawning continues into December.

Mountain Streams

El Paso's witnesses, Ward and Furniss, stated that mountain streams can safely be used for water withdrawal until flow ceases, at which time pools of water are isolated, difficult to locate, and important for overwintering fish. The time when flow effectively ceases seems to vary from mid-October until late November. It is not clear to what extend Arctic Gas relies upon this analysis, for it makes no separate identification of mountain streams. In Arctic Gas' exhibit identifying water sources, AA-43, the assumption is that Arctic Gas would not use this water source, but Williams did testify, however, that, while AA-43 did not consider mountain streams, they were a possible water source early in the season. Also, AA-43 concluded that subgravel flow in rivers is one "other" source that might be utilized. El Paso, in EP-238, Table 17 (p.51), identified seven mountain streams which can provide quantities of water until freeze-up. McCart testified that the impact of water withdrawal would be greater on smaller streams than larger ones, because there is a greater distribution of critical areas in larger streams.

Spring Streams

Spring streams, as Craig and McCart stated, are "habitats of relative stability and constancy." This stability appears to have a profound biological influence, and the springs have been described as a "green oasis in the polar environment" (Kalff and Hobbie, 1973). At this time, it is uncertain exactly how far downstream from the spring orifice fish spawn and overwinter. Everyone acknowledges that if a sufficient volume of water is withdrawn upstream of these critical areas, the fish downstream could be adversely affected. The main controversy of the water withdrawal area, therefore, is whether, and where, water can be withdrawn from spring streams.

Arctic Gas, through witness McCart and AA-43, takes the position that water can be withdrawn downstream as long as it is downstream from spawning or overwintering areas or the amount to be removed is sufficiently small in proportion to total discharge to have no effect. McCart stated a preference for the former alternative.

El Paso, through witnesses Ward and Furniss and EP-238, maintains that the distribution of fish in spring streams is not well enough understood to permit withdrawal of water. For example, Furniss testified that it has been reported that immediately after spawning, anadromous adult char begin to leave the orifice and go downstream. McCart conceded that char could actually spawn under the aufeis, although spawning typically takes place upstream of this area. El Paso concluded that water withdrawn from an "influence zone" (area extending from the orifice downstream in which spring water contributes significantly to the well-being of fish) could have a serious impact on fish. Since this "influence zone" has not been precisely located, Ward and Furniss recommend using only the two springs on the route which contain no fish, Okerokovik and Katakturak, as water sources. 1/

Lakes

Everyone agrees that lakes are the best source of water as far as environmental effects are concerned. The number of species inhabiting standing waters is low. Based on existing information, these lakes are little utilized by fish, and withdrawal of water from them can be considered to entail relatively

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1/ One of the problems here is that apparently the same water body is sometimes called a "spring stream," and other times a "mountain stream"; e.g. in EP-238, Table 2, the Kongakut is referred to as a spring source; in EP-238, Table 17, it is referred to as flowing water, as distinct from a spring source (only usable until freeze-up); and in AA-43, p.36, it is termed a spring source. It is impossible to know whether a spring source, spring stream and mountain stream all have the same name or whether the parties are referring to the same body of water.

little environmental risk. McCart testified that up to 50% of the Coastal Plain lakes don't support fish at all. He recommended either taking water from these sources or from the larger lakes that do contain fish. He cautioned against removing water from fish-inhabited lakes of marginal depth.

iv. Volume of Water Availability - Contrasting Studies

While believing that more precise information concerning water sources must and will be gathered during the final design stages, the evidence supports the Arctic Gas witnesses' conclusion that sufficient water is available on the North Slope which may be withdrawn without incurring significant environmental harm in terms of spawning and overwintering areas. The most recent water availability study prepared by Arctic Gas--AA-43 (April 2, 1976; discussed in Volume 156 and sponsored by Dr. McCart)--identifies specific potential water sources along the route, determines volumes available from these sources, compares volumes available with volumes required, and assesses the environmental impact of water withdrawal. Sources identified are usually confined to a corridor 5 miles wide on either side of the pipeline. While McCart testified that he preferred that water be taken from lakes and streams without fish populations, he believed that mitigative measures would be designed to allow water withdrawal from sources containing fish.

The study concludes that more than adequate water is available. The total requirement of 8,222,000 bbl would amount to about 1% of the approximately 550,967,000 bbl contained in lakes surveyed, assuming an ice depth of 1.5 meters. In addition, springs surveyed discharged approximately 5,807,000 bbl/day. Finally, other sources of water might be utilized (e.g. subgravel flow in rivers where surface flow is frozen). Water can be withdrawn from most of the lakes and springs surveyed without serious environmental damage, provided proper safeguards are observed, but before the final selection of water sources is made, there should be additional site-specific biological, hydrological and engineering studies. 1/

1/ The study recommends the following precautions during construction which are adopted here: (1) Volume of water withdrawn from lakes should not exceed 10% of the total volume of water available. There is no similar "safe
(Continued on next page.)

El Paso, in EP-238 ("Comparison of Water Availability for Use in Construction of Proposed Gas Pipelines on the Alaskan North Slope," discussed in Volume 161, sponsored by Ward and Furniss), presented an analysis of the prevailing literature (excluding AA-43) on water availability. This exhibit concludes that approximately 100 out of 195 miles of the Arctic Gas route in Alaska appeared to be seriously deficient in water supplies sufficient to meet estimated water requirements. The area in controversy is in the eastern portion of Alaska, basically from MP 70 to MP 190.

It has already been mentioned that, unlike AA-43, EP-238 only considers lakes over 2000 feet as potential water sources. The other major difference in the studies is their use of springs. In fact, in comparing the studies of water sources in the critical 120-mile area in eastern Alaska as presented in AA-43 and EP-238 (Table 17, p. 51), it is determined that the only major difference is the inclusion in AA-43 of several more springs as sources. El Paso, on brief, confirms that the basic dispute reflects different assessments of the safety of water withdrawal from springs (EP Reply Env. Brief, 32).

A more detailed summary of the exact sources proposed by Arctic Gas and El Paso in this critical area illustrates their different approach to springs. Between MP 70 and MP 190, EP-238 identifies two springs (Katakturak, Okerokovik), three streams and two lakes as potential sources of water. Among

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1/ (Continued from previous page.) withdrawal" figure for springs. Judgments there must be made on a site-specific basis, depending on where in the stream the water will be withdrawn. (2) During withdrawal, each location with known populations of spawning or over-wintering fish should be individually monitored. (3) Springs known to support fish populations should not be developed as sources if suitable alternatives are available. (4) If a spring is used, damage to aquatic environments can be minimized by avoiding rechannelization of natural spring channels, providing suitable barriers or screens to prevent fish from entering sumps or collection ponds, avoiding long lengths of access road parallel to spring channels, and withdrawing water from a single point downstream of the orifice and fish habitats (preferably at a point just above the aufeis field).

the three "streams" are the Hulahula and Kongakut, which EP-238 states can be used until freeze-up. AA-43, between MP 73 and MP 190, identifies seven springs (Katakturak, Okerokovik, Sadlerochit, Hula Hula, Ekaluakat, Kongakut, Clarence) and one lake as potential sources. AA-43 specifies:

1) MP 73 - MP 83 - use 2 Katakturuk Springs 5 miles from ROW; in repeated studies, no fish observed here.

2) MP 83 - MP 112 - use Sadlerochit Springs 7 miles from ROW; inhabited by overwintering fish.

3) MP 112 -MP 129 - use Sadlerochit Springs or Hula Hula Springs 2 miles from ROW; no fish observed in Hula Hula, but potential overwintering area for char.

4) MP 129- MP 146 - lake 5 miles from ROW could supply water needs with 0.4% of its total volume; no fish in lake; could also use Okerokovik Spring, which also contains no fish.

5) MP 146- MP 168 - small water requirements satisfied by Ekaluakat Springs, 5 miles from ROW; important spawning and overwintering site for Arctic char; need precaution, detailed studies.

6) MP 168- MP 190 - use Kongakut Delta Springs, 7 miles from ROW; important rearing and overwintering area for Arctic char.

Thus, it is clear that springs, some of which contain fish habitats, are important sources in this section of the Arctic Gas route.

v. Repopulation

Several witnesses testified, usually at the direction of the Presiding Judge, concerning the possibilities of restocking fish populations inadvertently damaged by water withdrawal during other construction. The witnesses agreed that, while fish repopulation has not been tested in the North, resident populations could probably be restocked. This assumes no permanent harm to the original habitat.

McCart testified that, if a portion of a stream was dewatered, it would be repopulated the following season by benthic invertebrates from upstream areas. The total population would be reduced for a period of time, but populations in this area are quite resilient. Thus, he stated that if only a portion of a fish population was eliminated and if it only occurred on a single occasion, the population would be reconstituted within a few years.

To his knowledge, there have been no attempts to move fish from one area to another on the North Slope. If an attempt was made to introduce the same species of fish from one stream to another, they may or may not adapt to that particular area. If they did, they would be somewhat different from the original inhabitants. If a portion of the regular population was still there, there might be competition between the two populations, and repopulation would be more difficult. McCart testified that it would be relatively easy to relocate resident populations, but more difficult to relocate anadromous populations. These fish have inherent migratory tendencies, although this might not be a problem for the Arctic char, since they use the coast as a migratory guideline (162/(26,750-756).

Ward and Furniss agreed that resident fish, like grayling, could be successfully introduced, but it would be more difficult to restock anadromous species. They also testified that lakes offer advantages over streams in terms of successful fishery rehabilitation. Arctic lakes do not have anadromous species, and studies have shown that lake fishery restoration can be successful in Alaska (161/26,548-554).

c. Birds

The principal consideration of the impact on birds varies in both short-term and long-term aspects, the construction period and timing, and the species under consideration. An example of a short-term effect would be the temporary destruction of a habitat due to construction along the pipeline right-of-way, and a long-term effect could be the impact of compressor station noise levels on the seasonal bird populations using the habitat. Mitigation includes careful planning of construction timing, ranging from discontinuing construction during sensitive times of habitat use or putting noise suppressors on compression stations.

The El Paso statement on the succession of bird life, while not limited solely to the North Slope, is excellent and is set out in full (Env. R. Br. p.47):

> The arctic coastal plain, from Prudhoe Bay to the Mackenzie Delta, is an important travelway for birds. Tr. 18/2,737 (Gunn). During the course of a year about 100 species use the plain; six species actually overwinter on the plain. Tr. 18/2,693 (Gunn). The first migratory birds arriving in the spring are probably eider ducks; they begin to arrive in April, probably a hundred thousand and perhaps more. Tr. 18/2,693 (Gunn). The first wave of birds consists of swans, geese, and ducks. The next wave, in May, consists of sandhill cranes, hawks, and small passerines. Tr. 18/2,694 (Gunn). The third succession, in late May, consists of shorebirds, the waders, sandpipers, and plovers. Tr. 18/2,694 (Gunn). Most birds have arrived by early June. Tr. 18/2,694 (Gunn). In the summer months the birds nest and moult. Staging snow geese use the plain prior to autumn migration. AA-13 (Gunn, p. 16). The first birds to leave are sandpipers in July and August. Waterfowl begin to move out in late July and August, with the main part leaving in late September and early October. Tr. 18/2,695 (Gunn). There is a general exodus of small birds and young birds in September. The eider ducks, who were the first to arrive, are the last to leave, in October. Tr. 18/2,694-2,695 (Gunn).
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> The foothills zone of the North Slope is very good raptor habitat. Tr. 11/1,860 (Roseneau). Gyrfalcons overwinter on the slope. Tr. 11/1,857 (Roseneau). Peregrine falcons make an appearance. Tr. 11/1,858 (Roseneau). Bald eagles, golden eagles, and rough-legged hawks arrive in March and leave in September. Tr. 11/1,862-1,864 (Roseneau). Marsh hawks frequent the North Slope in limited numbers. Tr. 11/1,865 (Roseneau). The nesting sites are closer to the Arctic Gas alignment in Canada than in Alaska, where the mountains and foothills approach much closer to the coast. Tr. 11/1,857-1,858 (Roseneau); Tr. 244/42,498 (Gunn); AA 13 (Gunn, p.17). 1/

1/ It should be noted that Roseneau distinguished the foothills zone from the Arctic coastal plain, which is poor raptor habitat. In that the Arctic Gas route passes some distance north of the foothills, Roseneau stated that no known raptor nesting sites occurred within 3 miles of the route (11/1860-64).

The Arctic Gas proposal to construct during the winter on the coastal plains and away from the foothills avoids most of the problems attendant to impacting bird life. In the Wildlife Range, there is a tremendous seasonal use (late spring through early fall) by migrating birds, including great numbers of water fowl. In addition to the few acres used by Arctic Gas for permanent roads, stockpile sites, and compressor sites and air fields which will directly affect bird habitat, the chief issue is air traffic and other noise. The greatest effect of these noises is on snow geese, which are not on the range in any numbers. The ornithologists hired by Arctic Gas recommended staying off the coast and not crossing the Mackenzie Delta, although Dr. William Gunn testified that even if the route did not leave the coast, it could be built without substantial impact to birds if proper mitigative measures were taken (AA 13). Dr. Gunn also testified that he was satisfied that the various raptors are sufficiently protected by both the Alaskan Arctic and Canadian Arctic routing, providing site-specific adjustments for undiscovered sites are possible (172/28,376). Dr. Kessel, Alcan's witness, was quite leery of the ability to effect mitigative measures and testified that the margin of error for many species is extremely precarious (214/37,044). Dr. Hickock, another Alcan witness, however, believed that birds are the most resilient species of animals on the North Slope, and he would opt for a route as close as possible to the coastline as the least environmentally detrimental to wildlife in general (206/35,319-35,320).

Essentially, the impact on snow geese by Arctic Gas construction and maintenance is their harassment by aircraft while feeding during the summer on the expanse of the arctic plain, barrier islands and in Mackenzie Delta. During the late summer and early fall, the snow geese are skittish, flushing and wheeling in large numbers when disturbed. There are few snow geese on the Wildlife Range itself, whether summer or fall (Hickock 206/34,320, 34,321). There are occasions, however, when large numbers of snow geese aggregate in the Mackenzie Delta, usually the result of early snow. The environmental impact, both short- and long-term, on snow geese is discussed <u>supra</u> in the Construction sections dealing with the Shallow Bay crossing of the Mackenzie Delta.

The overwhelming weight of evidence of the effect on birds in the Wildlife Range is that environmentally satisfactory mitigative measures can be taken to minimize short- and long-term impacts, that the damage to habitat except for those portions permanently used is <u>de minimis</u>, and that the long-term effects will not seriously or permanently affect bird populations on the North Slope.

d. Vegetation

Two potential problems concerning the effect of snow roads on the vegetative mat were identified on the record: impact on vegetation and compaction of the vegetative mat. All parties opposing Arctic Gas registered skepticisms, based on past failures of winter trails and not specifically on Arctic Gas' plan, that Arctic Gas would not damage the vegetation. A proper perspective of the arguments of opportunity made by the parties through all of the environmental briefs can be seen by comparing Alcan's description of the berm left by Arctic Gas construction 1/ with its statement of the vegetative damage which it will cause on its own line through comparable permafrost (Alcan Environmental Int. Br. 13):

> Vegetation. Unavoidable adverse impacts on vegetation are limited primarily to the aesthetic impact associated with vegetation clearing and the substitution of commercially available species during revegetation for the species occurring naturally. Given that revegetation will be successful, however, long-term impact associated with erosion, and other geotechnical concerns will be precluded. Hence, revegetation must be undertaken by all applicants as the primary means of mitigating vegetation impacts.

Alcan, which has done no revegation work, and must rely upon Arctic Gas' research and Alyeska's experience, unequivocally claims success while stating that Arctic Gas will fail. It is found, in part based on the Inuvik test described below, that Arctic Gas has shown that it can construct and operate its snow roads without a significant impact on the underlying vegetation and soils.

There was some discussion, especially in the FEIS of the DOI, "Alaska" (ST-26), indicating that snow roads would damage underlying vegetation and that snow collection activities may break off or uproot many plants. The Inuvik test (see snow road discussion) serves to disprove the suspicions of the impact statement. In that test, aboveground portions of evergreen shrubs were damaged. However, the vegetative mat remained intact, and subsurface parts of damaged shrubs sprouted the following fall to allow recovery of the vegetation. Arctic Gas witness Donald Dabbs cited the Inuvik test as proof that a processed snow road could protect the underlying vegetation. Dabbs testified that the shrub breakage was no more serious to the plants than a normal

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1/ "A 133 mile right-of-way marked by incompatible vegetation, a 2-3 foot berm followed by subsidence and ponding, disturbance to the thermal regime and vegetative mat and associated erosion and subsidence"(Reply Br. 8).

pruning. Regrowth the following year established that the road was not detrimental to the shrubs or the vegetative mat.

The concern over the damage of snow collection seemed to involve the fear of "scraping" snow off the tundra. The FEIS presumes that where snow could not be gathered from lakes, it would be "scraped" off the ground. Even if snow fences were used, the witness feared that the collector would go down to the level of the tundra vegetation (135/21,621-626). Dabbs disagreed. He testified that snow fences will be used which create snowdrifts of sufficient size to mechanically collect the snow without touching the underlying vegetation (10-11/1739-47).

e. Vegetative Mat Compaction

A more serious consideration was that the traffic on the snow road could compact the vegetative mat (peat) and soil, thus reducing the insulation properties of the surficial materials and promoting permafrost thaw. This would result in increasing the depth of the active layer. The increased depth of the thaw, according to the FEIS, then could cause subsurface water to concentrate in a linear depression, which would enhance thaw consolidation and accelerate deeper thawing of the permafrost. In addition, compaction of the vegetative mat could provide depressions where surface water will start to flow. This increased flow would enhance erosion and could result in the formation of new drainage patterns.

Although the FEIS has considerable discussion of vegetative mat compaction, the FEIS states that the extent of the compaction is unknown but generally should be slight to modest. (ST-26,262). DOI witness J. V. Coan confirmed that the FEIS really is indicating a lack of experience with the Arctic Gas-type snow road, and he is uncertain of its impacts. Coan testified that the ultimate impact would depend on vehicle use, alignment, vegetation, type of vehicle and number of passes. He concluded that while it might be technically feasible to mitigate damage, he believed some compaction would occur. However, Coan is not a vegetation expert and seemed to mostly rely on his observations of the damage of winter trails on the North Slope.

Arctic Gas relied on the results of its tests to counter the FEIS allegations. It was admitted that at the Norman Wells test, thaw depth was 65% greater than on the control site and compaction had increased peat density by 25%. However, Dabbs testified that the snow road at Norman Wells was not the type that Arctic Gas planned to construct. The proper equipment to make the road was lacking, and it was a case of compressing the snow that was there and essentially making an ice road.

At Inuvik, measurements of surface deviation, organic layer thickness and active layer thickness showed no significant change. Dabbs testified that the Inuvik test was selected as representative of the most difficult surface and slope conditions. He interpreted the test to prove that, with proper construction, secondary impacts like active layer thickness could be avoided.

The DOI witnesses, while admitting that the Inuvik test was auspicious, were generally chary of its application to the Arctic Gas project. The FEIS, and DOI witness Maxwell Britton, stated that the variance of results between Norman Wells and Inuvik suggests snow roads may be less damaging at higher latitude climates. Britton admitted that the Inuvik results were impressive, but had reservations concerning their use for 500 miles of snow roads. Britton did concede that the Inuvik results might have been more salutary than Norman Wells because of the difference in workpad thickness and the fact that some of the Norman Wells road was unprocessed. He concluded that, while Inuvik was generally applicable to the North Slope, differences and ambiguities made further tests desirable.

3. Northern Border and PGT

Northern Border proposes to construct, operate and maintain a 1,117 mile pipeline and related facilities, commencing at an interconnection with Canadian Arctic Gas' facilities near Monchy, Saskatchewan, and proceeding southeasterly through the states of Montana, North Dakota, South Dakota, Minnesota, and Iowa before terminating at a point near Dwight, Illinois. The proposed routing is reflected in the comprehensive seven-volume Environmental Assessment submitted by Northern Border with its application (Items NB-P, NB-R). Only Arctic Gas and Staff address Northern Border environmental considerations on brief. The Northern Border route, with the modifications required below, is found to be environmentally acceptable.

In its Initial Brief, Arctic Gas, reiterating the statements of its witnesses Merle Arr and Gerald Strobel, notes that it would not oppose conditions requiring changes necessary to avoid Ordway Memorial Prairie in South Dakota and Big Bend State Conservation Area and Starved Rock State Park in Illinois (Arctic Gas Initial Environmental Brief, 79). These areas were either not identified or did not exist in their present states at the time that Northern Border planned its route. Thus, because of the changed circumstances not previously evaluated by it, Northern Border does not oppose route modifications to avoid these areas, as suggested by the DOI FEIS (ST-28). The estimated cost of the route modifications to avoid the three areas is about $1,130,000 (NB-38), and applicant admits the changes can be effected with minimum cost and construction difficulty. A condition requiring the appropriate modifications, as detailed in NB-33, should be entered, if Arctic Gas is certificated.

The prairie pothole regions of North and South Dakota and Minnesota were identified by DOI and Northern Border as areas requiring special consideration. Potholes are water-holding depressions which, because of their particular hydrological characteristics (in particular, their ability to retain water), serve as important waterfowl breeding, feeding and migration habitat. Potholes occur in 300,000 square miles of prairie in the north central United States, and estimates of the number of potholes in North Dakota alone range up to 2.3 million (170/27,893).

The DOI FEIS suggests several mitigating measures to minimize disturbance to potholes, including route changes, appropriate trench-sealing methods and wetland restoration procedures. Northern Border has generally complied with these suggestions and has proved that its route can be constructed without significant adverse effect on potholes. The applicant has stated that it aligned its route to avoid as many potholes as possible. Moreover, Northern Border will now avoid the Ordway Memorial Prairie, one of the more important pothole regions crossed by the line. Second, Northern Border has submitted a wetland restoration plan (NB-29), which includes a pothole restoration program. During construction, potholes will be silty and muddy, but will usually not drain because the underlying soil is generally impermeable. To minimize impacts, the banks of the intercepted basins will be sealed by compacting the backfill. Where permeable soils are penetrated by the trench, the trench will be sealed with impermeable material (bentonite). Third, it is anticipated that Northern Border will design its pipeline so as to avoid affecting ground water flow that enters potholes. Finally, a revegetation program will be implemented.

Northern Border witnesses Strobel and H. W. Franks testified, moreover, that they either had experience in, or analyzed the results of, gas pipeline construction through pothole regions. For example, potholes were encountered along the Trans-Canada pipeline route, and they were either unaffected or adequately restored after construction (170/27,895). They concluded that the impact on the prairie pothole region would be minor and short-term. However, even in the "worst case" analysis of DOI, the impact on potholes will be limited to 2 years, with an estimated possible loss in production of 3,000 birds in the construction year and up to 1,000 birds in the next year (ST-28,539). This is inconsequential in comparison to the 1.7 to 1.9 million birds estimated to use the pothole region of North Dakota annually.

The DOI FEIS suggested, in the "Additional Mitigating Measures" section, three additional route modifications which are contested by Northern Border. Thus, despite its more than thousand-mile length, the only remaining disputes concerning environmental matters involve the proposed (1) crossing of the Little Missouri River, the Little Missouri Badlands and the Killdeer Mountains in North Dakota, (2) Wapsipinicon River crossings in Iowa, and (3) the Mississippi River crossing in Iowa. While the DOI FEIS proposed alternative routings in these areas, Staff's brief only suggested that "prior to construction, /Northern Border/ again evaluate Staff's proposed route modifications at the Little Missouri River, the Wapsipinicon River, and the Mississippi River" (Staff Initial Environmental Brief, Appendix B, 12).

Northern Border's position is summarized as follows:

> We believe that the Northern Border Proposed Route traversing the Little Missouri River, Badlands and Killdeer Mountains, and the Mississippi River, is preferable from an overall environmental standpoint to the modifications outlined by the DOI FEIS for these areas. Moreover, we foresee no significant overall environmental benefit arising from the rerouting of the pipeline to avoid the Wapsipinicon River Crossings. (fn. omitted; Arctic Gas Initial Environmental Brief, 80)

Northern Border presented an answering case in which it responded to the route modifications suggested by the DOI. NB-33 and NB-38, in particular, analyzed the various routing alternatives from environmental, construction and cost perspectives. All parties, including Staff, waived cross-examination of the Northern Border answering case witnesses.

It is found below that there is insufficient evidence to warrant the DOI-suggested modifications of the Little Missouri and Mississippi River Crossings proposed by Northern Border, although there is enough evidence to require Northern Border to continue to analyze possible alternative routes to lessen the impacts on both areas. On the other hand, the weight of the evidence is sufficient to require DOI's proposed deviation to avoid the two crossings of the Wapsipinicon River, and an appropriate condition should be entered if Arctic Gas is certificated. As to all three proposals, Northern Border shall reassess costs to attempt to reduce projected cost increases as it did so successfully for the Ordway Prairie, Big Bend State Conservation Area, and Starved Rock route modifications.

Northern Border proposes to have two crossings of the Wapsipinicon River. The crossings would involve clearing of about 6,000 lineal feet of woodland. The woodlands are a diminishing resource in this part of the country and serve aesthetic and wildlife habitat coverage functions. In addition, the Wapsipinicon River is designated 5(d) under the Wild and Scenic Rivers Act, which indicates possible future inclusion within the Wild and Scenic Rivers System. The proposed route modification would avoid both river crossings and the woodlands, but would require, according to the route description, about 4.5 miles of additional pipeline. Northern Border has projected additional costs for the route deviation of $3,260,000 (including the reduction of costs because of the elimination of river crossings). DOI's route modification, or a similar one avoiding the crossings if Northern Border can design one, is warranted and should be implemented by the applicant if certificated. The evidence is not overwhelming, but is deemed sufficient.

Northern Border proposes to cross the Little Missouri River, Little Missouri Badlands and the Killdeer Mountains. DOI suggests a Fort Berthold alternative, involving a crossing of the Little Missouri River and Badlands at a different location. This would also avoid the Killdeer Mountains.

It is uncontroverted that the badlands, mainly located in North Dakota, necessitate some special consideration. Given the erosive nature of the terrain, they are generally undisturbed areas with fragile plant communities, soil stability problems, and unusual aesthetic appeal. 1/ Northern Border conducted extensive field investigations in this area and selected a route through the Little Missouri Badlands which would maximize the use of level or almost level agricultural tableland and rangeland. The proposed route crosses badland soils for about 30 miles and the Little Missouri Badlands for about 7 miles. The DOI witnesses conceded that this is the narrowest Badlands crossing possible, but argued that while a more easterly crossing would impact approximately the same amount of Badlands, it would cross the Little Missouri River behind a dammed area where there is a state highway and an Amoco pipeline crossing. This would also avoid the Killdeer Mountains.

Northern Border argues that the proposed modification would require almost 6.5 additional miles of pipeline and more difficult construction, at an additional cost of $5,960,000 (NB-38). Rugged terrain would be encountered on both sides of the river, and the river crossing would have additional width, depth and rock. Moreover, it appears that the gas pipeline could not

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1/ NB-30 is Northern Border's Rangeland and Badland Restoration and Revegetation Program. The plan includes separation and restoration of the upper soil layer, importation of plant growth material, utilization of badland seed mixtures, and erosion control measures.

occupy the same benches and approaches as the Amoco line. Furthermore, the Northern Border prime route is located in a saddle in the Killdeer Mountains, on mostly level terrain, paralleling an existing country road. Thus, the route would avoid the high quality natural habitat on the slopes of the Killdeers. It is concluded that there is insufficient evidence supporting the route modification on environmental grounds to justify the increased cost and construction difficulties.

Northern Border proposes to cross the Mississippi River near Princeton, Iowa. The proposed route would cross a total of 4,500 feet in two separate island wildlife management areas-- Princeton Wildlife Area and Upper Mississippi River Federal Wildlife Refuge-- and would also cross the Big Bend State Conservation Area. It has already been decided, supra, that the Big Bend State Conservation Area should be avoided. Thus, the only relevant consideration left is whether to cross the island wildlife areas. DOI concedes that the route through the Upper Mississippi Range will affect only a minimal amount of woodland. However, it is feared that construction activities on the marsh will result in destruction of substrate and wildlife habitat (ST-28, 516; 542). DOI suggests a Mississippi crossing about two miles further south, thus allegedly avoiding bottomland sloughs (ST-28,649-650). However, in its answering case, Northern Border presented evidence, which was unrefuted, that the DOI diversion would not significantly reduce impacts on the areas of concern: the proposed diversion would still pass through the southern portion of the Upper Mississippi Refuge for 2,700 feet; of the 4,500 feet of wildlife management area crossed by the prime route, 2,000 feet lie adjacent to a powerline right-of-way, and the DOI route crosses 2,700 feet of wooded sloughs, compared to 2,500 feet crossed by the prime route (NB-33,7-9). In fact, NB-33 notes that high turbidities are characteristic of the Mississippi, and thus a temporary increase in turbidity during construction would result in a relatively low level of impact on the slough. Moreover, although the alternative route is the same length as the proposed route, it requires crossing the Mississippi River where it is wider and necessitates more difficult construction. Northern Border witness H.W. Franks testified that the alternative crossing requires a dual line under the railroad on the west bank in close proximity to sewage treatment ponds; on the east bank, construction would require tunnelling under another railroad in vicinity of the town of Cordova (170/27,905). Thus, Northern Border has estimated an additional cost of $4,270,000 for the DOI modification (NB-38). Northern Border's answering case remains unchallenged, and it is concluded that no deviation should be required. Given Northern Border's success in drastically reducing costs and findings routes of accommodation in other areas, a condition is warranted requiring Northern Border to further examine the possibility of avoiding the Wildlife Refuge.

The PGT application, as finally amended, hardly deviates from the existing line rights-of-way. Aside from site-specific environmental problems which may have arisen since the last construction on the right-of-way, there are few environmental issues at all, much less ones of significance. Staff's opposition is on the philosophical grounds that any environmental damage is significant if you do not need the facility in the first place. It is found, infra, that the facility is needed. In any event, from a purely environmental point of view, the short- and long-term damages would be minimal, as Staff concedes, and are acceptable.

E. El Paso and Alcan

1. General

El Paso's knowledge of the site-specific effect of its pipeline construction on the environment is limited, since much of the information available, such as in the Chugach Range, is general in nature. Alcan knows less. 1/ The fact of the matter is that El Paso, and possibly Alcan, apparently made a policy decision that it is sufficient for environmental purposes to meet NEPA requirements solely by identifying the most critical environmental impacts and giving a general plan as to how further site-specific work will be accomplished. There is really little to be said beyond this observation. El Paso could not help but acknowledge the limits of what it believed it was necessary for it to show, for it authorized no site-specific evaluations on environmental mätters. It relies almost exclusively on published literature, much of which is from Alyeska or derived from studies made by the JFWAT regulating groups supervising Alyeska.

As for Alcan, no question as to the depth of its environmental analysis had to be asked, since its minimum preparation in the spring and summer of 1976 did not even encompass a one year base period.2/Its key witness on fish, for example, believed

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1/ The superficial presentation madė by F. F. Slaney & Co. for the Canadian portion of the Alcan project was to meet the Commission's application requirements. By its own admission, there was insufficient work on the specific line location to permit site-specific recommendations (Dennis E. Baker 195/33,112).

2/ The following description of the genesis of the Alcan application set forth in El Paso's Geotechnic Brief (p.4) cannot be improved upon:

> ...Consultant studies supporting the Alcan project were not even initiated until April and May of 1976, Tr. 149/24,189-195 (McMillian), when it

(Continued on next page)

a good deal could be learned about fish in one year, but admitted that migratory fish runs of salmon occur on four year cycles and one had to luck-out on a good year. He thought 1976 was a good year (Dr. Paul B. Holden, 193/32,651).

On final analysis, the environmental position of both El Paso and Alcan is that if given a certificate, there is enough general knowledge about Prudhoe Bay, central, and southern Alaska to build pipelines in an environmentally sound manner and that enough additional information could be learned between the time a glimmer of a favorable decision appeared and the time they were called upon to build a pipeline. Alcan, of course, if one accepts at face value its claim to be able to mount an early construction schedule, does not have even that much lead time at all. What this record is left with, therefore, is a minute dissection of every aspect of Arctic Gas' plan, because it is most complete to begin with, but only vagueness and non-specificity when it comes to discussing the other two projects.

2/ (Continued from previous page)

became apparent to Northwest Pipeline Corporation (hereafter "Northwest"), after issuance of the FPC Staff draft environmental impact statement in November of 1975, that further consideration should be given to an alternate route. Tr. 149/24,167 (McMillian). Northwest's Board of Directors did not authorize the necessary filings until May 7, 1976. Tr. 149/24,165 (McMillian); Exhibit NW-100. After a premature gestation period of a few short weeks, the applications of Northwest and Alcan were filed on July 9, 1976. The applications were extensively supplemented by filings on July 19, 1976. Alcan then proceeded to file additional evidence periodically up to and including the close of the record on November 12, 1976. Tr. Vol. 253....

2. Corridor Concept

A major component in the environmental impact equation of both El Paso and Alcan is the common utility corridor concept: that is, the grouping or clustering of energy transportation facilities to form a single corridor. Two of the three applicants have employed this corridor concept in aligning their respective routes. This discussion is directed solely to the environmental aspects of the corridor concept.

Under its base alignment, El Paso's 810-mile, 42" pipeline from the Prudhoe Bay field to the Gravina Point LNG facility would run parallel and close (within 3000 feet for 85% of the distance) to the Alyeska oil pipeline for 766 miles. For the 30 miles through the Chugach Range, El Paso crosses almost virgin territory. The State of Alaska during the hearing pursued a realignment of the pipeline, which El Paso has prepared and presented. (El Paso still favors its base case alignment.) Under this realignment case, the pipeline would be 13 miles longer but also almost superimposed upon the Alyeska line and haul road.

The Alcan project, evolved after the State's strong views were known, also employs the corridor concept. Its 731-mile 42" pipeline in Alaska from the Prudhoe Bay field to the Yukon border parallels the Alyeska line for 539 miles and the abandoned Haines oil pipeline and the Alcan Highway for 192 miles. In addition, the majority of the remainder of the Alcan project consists of the looping of existing pipelines: Northwest's mainline in Washington and Oregon; Westcoast's line in British Columbia; and AGTL's line in Alberta. Furthermore, Foothill's pipeline through the Yukon would follow the Alcan Highway.

On brief, El Paso, Alcan, Alaska, and the Conservation Intervenors support route alignment along the Alyeska utility corridor as environmentally superior to the route alignment of Arctic Gas through the Arctic National Wildlife Range--a relatively untouched area. In support thereof they contend that the record evidence establishes several environmental advantages to alignment along the Alyeska corridor. First, they assert that the impact of pipeline construction, operation and related human intrusion upon wildlife will be minimized by confining such intrusion to a previously impacted area. In this regard it is argued that the Alyeska construction has already driven away, and Alyeska operation will continue to drive away, those species which cannot tolerate human intrusion, and construction and operation of the gas pipeline will impinge upon only those species which have adapted to human intrusion; thus, a lesser impact will occur upon wildlife than would occur from an alignment through previously unimpacted wilderness. Second, they further assert that alignment along the Alyeska oil pipeline corridor would provide the applicant with a wealth of site-specific environmental and geotechnical data compiled from actual Alyeska experience over the same territory, if not the same right-of-way. Third, they argue that by constructing the pipeline along an existing corridor, the applicant can avoid the impact of new roads, work pads, right-of-way clearing, work camps, and other logistic facilities upon unimpacted areas. This would mean no access into new areas for hunting and fishing and less adverse impact, such as siltation during stream crossing and permafrost degradation, on the terrain, both in terms of geotechnics and aesthetics. These three alleged benefits of utility corridor alignment are best summarized by the phrases "localization of all environmental impact" and "incremental," rather than new, impact.

Arctic Gas advances a number of arguments against aligning gas pipelines in the Alyeska corridor: (1) that amendment of the Mineral Leasing Act of 1920 by passage in 1973 of the Trans-Alaska Pipeline Authorization Act, 30 U.S.C.A. § 185 (p) (1973) was not intended by Congress to establish the Alyeska corridor to also be used for a gas pipeline; (2) that the respective El Paso and Alcan routes are equally subject to considerable seismic risks along with the Alyeska project; the entire supply of North Slope hydrocarbons (oil and gas) could be interrupted by a common seismic catastrophe which, from an environmental point of view, would require substantial additional construction for repairs as well as deprive consumers of clean-burning gas; (3) that an Alyeska corridor alignment is incapable of later connecting the substantial potential gas reserves to the east of Prudhoe Bay without massive additional construction in the very area which would now assertedly benefit from remaining untouched; (4) that alignment along the Alyeska corridor would not be environmentally superior, as the Maple Leaf Project would still have to be constructed also through relatively untouched Canadian wilderness to transport Mackenzie Delta gas; (5) that no concrete scientific evidence was introduced demonstrating the superiority of Alyeska corridor alignment.

In this vein, Arctic Gas also seeks to refute the evidence that was relied upon by proponents of the corridor concept: a) by detailing record evidence 1/ to support the conclusion that an alignment by either El Paso or Alcan through the Alyeska corridor, not its own alignment, will increase access to new areas because El Paso and Alcan each would use and construct permanent haul and access roads (including permanent work pad), while Arctic Gas would rely almost entirely upon snow roads; b) in answering Alcan's claimed advantage of using existing access for construction, maintenance and repair, by arguing in rebuttal first of all that Arctic Gas similarly will have ready access via the Mackenzie River and highway and the Beaufort Sea and second that it has developed repair plans which will minimize impact upon the terrain where the route diverges from existing access2/; by charging that the incremental-impact-upon-wildlife justificatión for Alyeska corridor alignment is both unproven by specific project evaluation and also factually incorrect in light of the evidence that corridor alignment could well result in a synergistic or cumulative impact greater than the sum of the separate impacts from the oil and gas pipelines3/; c) and, finally, by attacking the corridor concept rationale that site-specific environmental data generated from Alyeska experience will be utilized to reduce the impact of a pipeline built along the Alyeska corridor. In this regard, Arctic Gas asserts that whichever applicant is chosen will have access to the results of the Alyeska environmental monitoring but that only Arctic Gas has in fact employed the Alyeska monitoring

1/ Arctic Gas witness Clark (244/42,518); El Paso witness Murphy (61/9150, 9187, 9291, 9293, 9294, 9309).

2/ Arctic Gas witness Dabbs (244/42,492); Stern by reference AA-Q, Chapter IV, pp. 49-50).

3/ Arctic Gas witnesses Banfield (22/3287, 3322; 191/32,415-32,421; 244/42,540-42,541); McCart (172/28,332; 244/42,499-42,500, 42,504); Dabbs (244/42,490); and Jakimchuk (244/42,553).

procedures (Arctic Gas witness Gossen, 172/28,195). It also views this Alyeska environmental data, including the Wildlife Atlas, Trans-Alaskan Oil Pipeline, Valdez to Prudhoe Bay, Joint State/Federal Fish and Wildlife Advisory Team (Summer, 1976), as inferior to its own Corridor Wildlife Map Series, which has far more site-specific baseline data (Staff witness Campbell, 235/41, 019-41, 020, 41,037-41,038).

There can be no presumption that there is less environmental impact by incremental construction than by construction in a new area. Review of the evidence introduced in support of corridor alignment of the gas pipeline, in particular the Alyeska corridor, 1/ does reveal numerous environmental witnesses who favor the alignments of the El Paso and/or Alcan projects which would parallel to an extent the Alyeska pipeline and haul road and the Alcan Highway. This support for the corridor concept, which is extensive, appears to be founded on an *a priori* expectation and almost no actual field research. Thus, while this evidence, 1/ is entitled to some weight, it cannot be said that project alignment along the Alyeska corridor necessarily indicates environmental superiority for either the El Paso or Alcan projects.

1/ Alcan witnesses Bromley (205/35,132, 35,136, 35,142, 35,246-35, 247, 35,263-35,265, 35,271), Kessel (214/37,021, 37,026--37,027, 37,041-37,043, 37,063, 37,074-37,075, 37,080, 37,087-37,088, Holden (193/32,613,32,616, 32,683-32,684), Tilley (217/37,840, 37,842), Whitney (217/37,733), Carlson (194/32,736); El Paso witnesses Murphy (61/9280; 62/9462; 169/27,710), Wright (169/27,795); Alaska witnesses Le Resche (140/22,428, 22,456, 27,457, 22,517; ALA-23, pp.3-4,7), Champion (ALA-12, pp.13-14); Staff witnesses Campbell (235/40,960, 41,011-41,012, 41,018-41,019, 41,021, 41,023-41,025, 41,027, 41,029), French (235/41,003, 41,005-41,007), Barcelona (235/41,005), Behkle (40,816-40,817), Staff Exhibit St-52, p.366, App.6.

Nor can it be said that the experts giving their opinions are all of the same mind. Some, albeit mostly Arctic Gas witnesses, have concluded that the incremental environmental impact associated with a pipeline aligned along the Alyeska corridor could be more than the environmental impact of the Arctic Gas project alignment. Arctic Gas' alleged synergistic impact phenomenon, as opposed to incremental impact, however also lacks site-specific record evidence. 1/ Such general evidence also falls short of that evidence necessary to demonstrate that a specific corridor alignment is inferior. On the other hand, the conclusion is ineascapable that El Paso and Alcan have the burden of proving that their respective projects are environmentally acceptable by site-specific evidence, not merely by the fact that they are in a "corridor." Each has partially failed to meet this burden much less show superiority over Arctic Gas. 2/

This is not to suggest, however, that the corridor concept has no merit, and many witnesses testified to its general desirability. From the aesthetic and construction point of view, in fact, it clearly has merit if the construction is on the existing rights-of-way of conventional pipelines as proposed by AGTL, Westcoast and PGT. That is not the case in Alaska, however, for Alcan and El Paso will build gravel pads and roads across the breadth of Alaska, and what their construction represents even in the so-called corridor is permanent loss of habitat, need for additional borrow sites, and easy hunting access absent regulation. This is what must be compared to Arctic Gas' snow road construction, and it is difficult to understand the overall merits of the corridor on aesthetic grounds on this basis. Alcan will leave a gravel "road" and scars of cleared access for the work pad parallelling and diverging from the Alcan Highway for 192 miles from the Yukon Border to Delta Junction. It would also widen by at least 25 feet, and probably more than 50 feet, the existing Alyeska pad from Delta Junction to Prudhoe Bay--the equivalent in size of another three-to six-lane superhighway through the State. El Paso will do the same if it is forced to build the realignment case off the existing Alyeska pad and, if not, may have to build some roads to its snow work pads up to one-half mile away. For 33 miles through the

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1/ On Rebuttal Brief, Alcan argues that the best example of known synergistic impact may be the effect on the Porcupine herd through hunting on its winter range and Arctic Gas construction on the calving grounds (Br. 17).

2/ While JFWAT material is site- specific to Alyeska and generally is relevent, it is not necessarily site-specific to either El Paso or Alcan.

Chugach Mountains it must cut a roadway, and even if El Paso does not wish to call it a road, a road it is. Aesthetically, these plans leave a lot to be desired. To speak to the issue just on the basis of environmental or synergistic effect on wildlife is to ignore the aesthetic impact of major permanent road construction on the rights-of-way, even if it is within an existing area already partially so affected.

3. El Paso

An overview of El Paso's trans-Alaska pipeline from the Prudhoe Bay field to the Gravina Point LNG plant and marine terminal is set forth in the construction discussion supra. Additional details of its proposal are set forth in Volumes IV and V of El Paso's application (EP-97 and 98) and Volume II of Staff's Final Environmental Impact Statement (FEIS, ST-19). During the proceeding and on brief, Staff, Alcan and Arctic Gas emphasized, while El Paso minimized, several specific points of environmental concern for this trans-Alaska segment of El Paso's project. These are addressed *seriatim*.

a. Chugach National Forest

The Chugach National Forest was established by a Presidential Proclamation of Theodore Roosevelt on July 23, 1907. 35 Stat. 2149 (1907). The actual land area of the forest has been subsequently modified on numerous occasions.

El Paso diverges from the Alyeska pipeline route south of Thompson Pass and enters and crosses the Chugach Forest for 33 miles to reach the Gravina Point LNG plant. Gravina Point is in the Chugach Forest. (See descriptions in DEIS Vol. II, 81, 82) El Paso acknowledges that the Chugach Forest has wilderness value, but asserts that the only major impact of its construction is aesthetic, since the Chugach Forest contains no habitat critical to any wildlife population. An alignment through the Chugach Forest is environmentally sound, it asserts, since the Chugach Forest was established for multiple use and is not a unique area so as to preclude intrusion. The State and Conservation Intervenors agree, although the Conservation Intervenors opt for Alcan in part because Alcan will not enter the Chugach Forest and does not involve LNG technology.

Staff argues that El Paso's alignment through the Chugach Forest will severely impact wildlife and that Gravina Point, which is within the Chugach Forest, constitutes important, if not critical, habitat for Sitka black-tailed deer and bald eagles.[1/] Alcan echoes Staff's concern that the Chugach Forest contains critical habitat for several species. Besides the Sitka black-tailed deer and bald eagle, it also lists mountain goats and brown and black bear. Alcan adds that the Chugach Forest is a wilderness area in fact, even though it has not yet been so nominated by the Departments of Interior or Agriculture, and that El Paso's intrusion therein would open the area to development. Conservation Intervenors espouse this same position on brief.

It is clear from the record that construction of El Paso's pipeline through the Chugach Forest and the LNG plant at Gravina Point will have some impact upon the wildlife of the region. As will be discussed below, however, the extent of this impact, the nature of the species affected, and the potential for mitigation of this impact require a finding that alignment of El Paso's pipeline through the Chugach Forest and placement of the LNG plant at Gravina Point do not warrant rejection on environmental grounds.[2/]

There is no dispute that the Chugach Forest, across which El Paso's pipeline would run and in which its LNG plant would be situated, is wilderness in fact (140/22,488). As with the Wildlife Range, however, it is not designated as a "wilderness" under the Wilderness Preservation Act.

First, there is no access by road, including the town of Cordova (population 1164) which is thirteen miles southeast of the Gravina LNG site (ST-19, p. II-463). No permanent access road across the Chugach Forest is contemplated by El Paso, so that the wilderness nature of the Chugach Forest, including Gravina Point, should not be significantly reduced by the project itself. However, there is more than some indication that Alaska is considering the industrialization of Prince William Sound and, in particular, utilization of its royalty gas to foster a petrochemical industry (ALA-20, pp. 12-14). While it might be argued that this industrial development would materialize in any event, Staff witness Sotak felt that running El Paso's pipeline through the Chugach Forest would open it up for

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1/ Staff contends that the LNG plant would block the shoreline along which the deer must walk during times of deep snow in search for food. It contends moreover that the LNG plant and cryogenic tankers could affect the large number of active eagle nests near the plant (16 nests within 5 miles).

2/ It has already been demonstrated that El Paso's Gravina Point LNG site is superior in terms of navigation and engineering design to the other possible sites, Hawkins Island and Bidarka in Prince William Sound and Cape Starichkof in Cook Inlet.

development (145/23,567). The Conservation Intervenors also fear renewed interest in the presently moribund Copper River Highway project. If El Paso's project were to be certificated, an important environmental condition to be attached, if the wilderness and wildlife values are to be protected, would be that no permanent access road remain after construction. This condition would also contemplate El Paso's insuring that its right-of-way through the Chugach Forest is not open to four-wheel drive vehicles. Of course that is no guarantee that the Chugach Forest will not be developed, since Alaska views it as conducive to multiple use (Alaska witness Le Resche, 140/22,449-B). This decision, however, should be made on its merits, and the Commission, through inadvertence, should not permit unlimited access.

Although construction and operation of El Paso's system through the Chugach Forest will have significant long-term impact upon the terrain, these are within acceptable limits if the public interest otherwise requires certification of El Paso's project and an LNG facility at Gravina Point. Pipeline and LNG plant construction may also destroy some of the habitat of Sitka black-tailed deer (EP-98, p. 3A 4-13; ST-19, pp. II-462, II-516(b)). There are, however, ten thousand or so Sitka black-tailed deer in southeastern Alaska, of which several thousand inhabit the Prince William Sound area which is the northern portion of their range; several hundred of these deer over-winter in three beach fringe zones, the most important of which is an 8.5-mile section on Gravina Point which encompasses the LNG plant site; these deer need this type of winter habitat which consists of conifers growing down to the tideline, such coniferous vegetation preventing deep ground accumulation of snow and thereby permitting movement to the beach where the deer can locate and eat kelp and other marine plants when the tide is low; and, construction and operation of El Paso's LNG plant at Gravina Point would infringe to a limited degree on this significant winter habitat (140/22,498, 22506-22507; 205/35,143, 35,197-35,203). The total effect upon the deer population is essentially insignificant. Imposition of certain conditions which would limit the destruction of the shoreline trees where possible, moreover, would minimize even this small impact and could lead to the successful coexistence of the LNG facility and the over-wintering of the black-tailed deer.1/

1/ This final conclusion is further buttressed by an examination of El Paso's slide presentation of the Gravina Point site (EP-143, slides 30,31,32,37,38,39,40,42, and 43) as presented by El Paso witness McCollum (59/8915-8920).

The impact upon the Alaskan bald eagles nesting at Gravina Point, a different species than the southern bald eagle, was also part of the evidentiary showing by El Paso. As of 1975, there were 16 bald eagle nests within five miles of the LNG plant site, one of which is actually on the site (ST-19, pp. II-461, II-519b). Such proximity to man might lead some of these eagles to leave their present nests, but, since the bald eagle population numbers in the thousands, this possible, though unproven impact would be minor (140/22,410-22,411). Dr. LeResche considered the impact minimal, and it is so found.

Finally, while it is true that the El Paso alignment transverses very favorable mountain goat habitat west of Keystone Canyon (population estimated at 300 to 400 goats) and river valleys and lowlands constituting spring habitat for brown and black bear (205,35,144), there is no indication that the pipeline construction will significantly impact such large mammals.

b. Gravina Point LNG Plant

The greatest potential environmental impact, other than crossing the Chugach Forest, may result from operation of El Paso's LNG plant. El Paso proposes to construct a once-through sea water cooling system, and the effect of this system upon the marine biota of the adjacent Orca Bay in particular and Prince William Sound in general is questioned. After intake, an algacide would be added to the water, and before discharge a neutralizing agent would be introduced. The returned cooling water would average 20.7°F warmer than the water in Orca Bay, and the design flow would be 494,000[1/] or 658,000 gallons per minute respectively for El Paso's 2.4-Bcf and 3.2-Bcf designs.

El Paso justifies its choice of once-through sea-water cooling over air cooling by alleging that it is the most economical, energy efficient, and straightforward in design and aesthetically acceptable. It also contends that its water cooling system can be implemented in an environmentally sound manner, noting that the estimated 21°F temperature rise is much less than the typical 30°F rise, that this 21°F rise could be reduced, that Alaska will approve such a temperature rise so long as there is only a 2°F rise at the edge of the mixing zone, and that it is prepared to add a discharge water diffuser to further mitigate the impact.

1/ This is equivalent to about 67,000 cubic feet per minute, a 40-foot times 40-foot 4-story building.

Staff, Arctic Gas and Alcan all contest El Paso's position on once-through sea water cooling. They emphasize the dirth of baseline oceanographic data, thereby rendering impossible any meaningful environmental evaluation of once-through cooling. Staff, moreover, questions the credibility of El Paso's economic choice of once-through sea water cooling, claiming that its witness had not done design studies, and it points to Pacific Alaska LNG Company's certificate application in Docket No. CP75-40 to demonstrate the feasibility of air cooling towers in place of water cooling towers or once-through sea-water cooling. It also belittles El Paso's reliance on limiting thermal impact to the mixing zone as obscuring the lack of actual knowledge of the impact of temperature rise and herbicides upon the biota within the mixing zone. Staff in fact claims that El Paso wants the regulations rewritten to accommodate whatever thermal pollution its mixing zone produces (Br. 21).

The state of the record precludes any dispositive finding concerning the environmental impact of El Paso's once-through sea water cooling system upon Prince William Sound marine biota. This record shows that El Paso has performed none of the prerequisite baseline oceanographic population and temperature tolerance studies necessary for affirmative findings to be made (EP-98, p. 3A.4-22; ST-19, p. II-279; 60/9245; 140/22,408; 141/22,558; 144/23,311-23,313).1/ Absent such studies, the finding must be made that there could be unacceptable impact from this once-through sea water cooling upon marine life of Prince William Sound, in particular from the thermal stress and the chlorine (anti-fouling biocide) and brine effluent (ST-19, pp. II-279-II-282). El Paso simply does not know.

El Paso states in its Rebuttal Brief (p.6) that it is not wedded to a once-through sea water cooling system, although it is simple and efficient. Air cooling tower systems are feasible in terms of engineering and environmental design: Pacific Alaska LNG employed air cooling towers in its design (141/22,564-22,565), and the existing Phillips-Marathon LNG plant at Kenai on Cook Inlet employs cooling towers instead of once-through sea water cooling (170/27,922-27,923). El Paso's LNG plant design must include cooling towers unless a clear showing by El Paso is made that its once-through sea water cooling design will, in fact, not adversely affect the marine

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1/ El Paso cities in its Initial Env. Br. (p. 40) certain research being performed under the auspices of the University of Alaska (described by Dr. Murphy, 60/9,171). The impression is left that the record discloses continued research on this issue. The research described, however, is general in nature and not one word is directed to the issue at bar here.

biota in Prince William Sound. The higher capital costs and less efficient aspects of air cooling systems, while not quantified, are substantial, but this is a small price to pay to prevent the possible harm to Prince William Sound.1/ The fuel efficiency of the El Paso plant design would apparently also be adversely affected. (See supra.)

c. Other Wildlife

Apart from the species found in the Chugach National Forest, El Paso seeks to downplay the impact of its project on other species. While it admits that both the Western and Central Arctic caribou herds on occasion cross Atigun Pass in which Alyeska, the haul road and proposed El Paso alignment are also located, El Paso notes that the Alaska Fish and Game Department has wildlife researchers who are observing the migratory patterns of the Central Arctic herd, thereby providing information needed to mitigate impact on caribou migration. El Paso also concedes that its alignment touches the overwintering grounds of the Western Arctic, Nelchina, Delta and Forty Mile caribou herds, but it asserts that its winter construction, thereby contacting overwintering grounds, causes much less impact than would summer construction, which would contact caribou calving grounds.

El Paso moreover attempts to minimize concern that construction of its pipeline might impact peregrine falcons nesting north of the Brooks Range on the Franklin and Sagwon Bluffs. Its base-case alignment would sufficiently bypass these bluffs, while the realignment case following the haul road would come much closer. It is prepared to further realign its route past these bluffs to avoid adverse impact on the nesting. It argues that despite Alyeska construction nearer than its base alignment to the bluffs, the falcons are still active, and even without the gas pipeline, continued use of the haul road would impact the falcons. Its winter construction would not impact the falcons during their most sensitive period of April and May.

On brief, only Alcan addresses the impact of El Paso's pipeline upon other wildlife, although its criticism is limited to the conclusory statements that El Paso's winter construction could impact overwintering "moose, caribou and other species" more than would Alcan's construction and that El Paso's route south of Delta Junction would touch highly sensitive populations of sheep, waterfowl, caribou, raptors and fish.

1/ In its Rebuttal Brief, El Paso refers to out-of-record material showing why Pacific Alaska LNG Company designed its systems with air cooling towers. Assuming that these alluded-to facts were proven, they do nothing to overcome El Paso's failure of proof here as to the harm its cooling system might cause.

Construction of El Paso's pipeline, primarily as it passes through the Brooks Range, will contact several different herds of caribou; however, with proper scheduling of construction, the resulting impact can be minimized. El Paso's alignment, whether base-case or revised, does cross to varying degrees the ranges of the Arctic, Porcupine, Brooks Range, Forty Mile, Delta and Nelchina caribou herds. Between caribou calving and overwintering range, the former is more sensitive to human intrusion (140/22,421-22,422, 22,451), and El Paso's alignment safely avoids the calving grounds of all five of these herds (ST-19, p. II-290; ST-22, pp. II-200 and 202; 141/22,548). There is minor intrusion of El Paso's alignment through the overwintering ranges of the Nelchina, Delta, Forty Mile, Porcupine and Brooks Range herds (62/9361-9363; 140/22,440; 141/22,548; 145/23,506-507; ST-19, p. II-290; ST-22, p. II-201).

The greatest potential impact could be upon the Arctic herd as it migrates through the drainage systems of the Dietrich, Atigun and Sagavanirktok Rivers between wintering and calving grounds. Of particular concern is the alignment through the Brooks Range at Atigun Pass, through which the pipeline would parallel Alyeska and the haul road. While this north-south migration follows the entire drainage system, which spreads out many miles from either side of these three aligned rivers (62/9355), an unquantified number of caribou migrate through Atigun Pass (62/9358). Without considering the impact of Alyeska pipeline construction and operation and activity along the haul road, the critical question concerning El Paso's alignment through Atigun Pass is whether this spring migration north will be impeded by construction. The peak of this migration is in April (62/9358), while El Paso plans summer construction through Atigun Pass which should not commence in full until after this migration (62/9359). It is clear that impact upon this migration can be avoided, and any certificate granted to El Paso should contain a condition requiring refinement of both the Arctic caribou herd migration and pipeline construction timetables so as to minimize any impact.

Consideration of the peregrine falcons is essential, since they are an endangered subspecies in Alaska (214/37,023). El Paso alignment along the Sagavanirktok River between the Brooks Range and Prudhoe Bay bypasses two bluffs which contain active peregrine falcon aeries (nests). Franklin Bluffs are located a mile or two to the east of the Alyeska pipeline and haul road at about MP 35. As the El Paso alignment passes the peregrine falcon aeries, it is to the west of Alyeska and about 2.5 miles from Franklin Bluffs (62/9378). Sagwon Bluffs are slightly west of the Alyeska pipeline and haul road and about one mile east of El Paso's proposed alignment at about milepost 70. (62/9380). It is unclear from the record what is an adequate distance for bypassing such aeries to avoid forcing the falcons to abandon their nests (214/37,049-37,051), but it is clear that site-specific realignment at either Franklin or Sagwon Bluffs to prevent adverse impact upon the peregrine falcons could be accomplished. In addition to the question of distance from these bluffs, construction schedule is also germane. The peregrine falcons are the most sensitive to intrusion during the egg-laying and incubation period, which occurs in April and May, and it is imperative that heavy construction, in particular blasting, be avoided during that period (214/37,048; 235/41,030). El Paso's winter construction in this region should be satisfactory in this regard.

d. Revegetation

One of the principal environmental problems in the arctic and alpine tundra following the El Paso route from Prudhoe Bay through Atigun Pass and south is revegetation. El Paso asserts preliminarily that its winter construction schedule should minimize the impact upon the permafrost terrain and that, accordingly, the principal long-term impact upon the pipeline right-of-way is aesthetic (235/41,024 - 41,025). Adequate and immediate revegetation of disturbed permafrost areas, as described above, is necessary to prevent both geotechnical and environmentally unacceptable damage. Although El Paso has performed no revegetation studies of its own, it argues that it should be allowed to rely to the Alyeska revegetation plan, albeit not yet complete, since its plan follows the same corridor alignment. Given the time differential now apparent between completion of Alyeska and the beginning of its construction, it argues in its Rebuttal Brief that experience and material (seeds) will be available. While Alcan does not comment upon El Paso's revegetation "proposal" since it relies on Alyeska's experience also, it attacks El Paso's reliance upon winter construction which it contends would more severely impact over-wintering moose, caribou and other animals than would Alcan's construction.

Arctic Gas does not argue that revegetating the areas disturbed by El Paso is impossible. It adamantly assails, however, the wisdom of El Paso's total reliance upon the incipient Alyeska revegetation plan, asserts that preparation of a revegetation program tailored to a particular proposal is absolutely necessary, that such a proposal would take substantial time and qualified personnel (199/33,832), and that El Paso, unlike itself, has not embarked on such a program and has not and cannot determine the type, availability, and cost of the seeds necessary to properly revegetate the impacted terrain.

There is no question that more confidence could be placed on El Paso's claims if El Paso had embarked upon substantial revegetation planning, including the required plant community surveys, seed selection and availability, and fertilization. Its failure to do so effectively precludes definitive findings that its cost estimates are valid, although its witnesses stated that adequate funds had been provided. There is also no question that El Paso will have access to substantial applicable general information as well as a good deal of site-specific revegetation data developed by Alyeska. It will also have available general information from Arctic Gas' research. It could also have sufficient time to develop its own revegetation plan during the several years between certification and construction of its project (El Paso Witness Murphy, 60/9250-9252; 62/9339, 9342-9345, 9448-9450, 9478-9480). In addition, state and federal scrutiny of revegetation, including the imposing of conditions upon any certificate, should provide adequate guarantees that revegetation is successful.

4. Alcan

As far as this record is concerned, Alcan's descriptions on brief of the story it has to tell on its environmental preparation far exceeds the contents of the story. From Prudhoe Bay to Delta Junction, as of now, it simply relies on Alyeska work as supervised by JFWAT and a literature search by its consultants (Rebuttal Br. 23). From Delta Junction to the U.S.-Canadian border, it "follows the Haines pipeline and highway," even though its environmental witnesses were not sure where the pipeline would go. The corridor concept is argued as if it were on a common pipeline right-of-way -- which it is not -- leaving Delta Junction and as if merely saying the magic word "corridor" eliminates the problems of site-specific work. In both its Environmental Rebuttal Brief and Economic Brief, Alcan argues that its ongoing studies on environment will be more complete by May 1, 1977, when the Commission's decision will be entered -- an almost bald admission that the record showing it has made so far is deficient on its face. There are no JFWAT studies east of Delta Junction, and there simply is not sufficient biological evidence in this record to find that Alcan has met the Commission's requirements under NEPA.1/ The environmental showing made as to the Canadian portions of its project were not even used by the engineers in Canada in designing the line. On the basis of this record, the only advantage that Alcan can be found to have is that it crosses neither the Wildlife Range nor the Chugach Forest. Other than that, which is a philosophical finding, it has not made a case sufficient to make appropriate environmental findings that it is as satisfactory, and certainly not that it is superior, on environmental grounds as either Arctic Gas or El Paso.

1/ An interesting sidenote is El Paso's admission in its Rebuttal Brief (p.19) that it aided in the preparation of the JFWAT report.

5. Comparison With Maple Leaf

All other things being equal, it is axiomatic that avoiding environmentally "sensitive" areas is desirable. It would follow, therefore, that if all other aspects of the case were equal, a route avoiding both the Alaskan National Wildlife Range and Chugach National Forest would be environmentally more desirable than ones that do not. Mr. Lynn A. Greenwalt, the Director of the U.S. Fish and Wildlife Service, relied upon this very axiom in rendering his opinion about crossing the Wildlife Range. The DOI and Staff environmental witnesses, relying only on environmental considerations and looking solely at Alaska, also favor avoiding the Wildlife Range and the Chugach Forest. The latter favor a Fairbanks alternative, something akin to Alcan in Alaska.

First, the difference between Arctic Gas' projected 185-mile incursion through the Alaskan Wildlife Range and the 800- or 900-mile Alcan pipeline which Alcan proposes to build through the rest of Alaska clearly makes on its face "other things not equal." When added to the fact that the environmental impact of Alcan's route can only be hypothesized at best and that there is almost no specific proof of what, when, or how it will construct its pipeline, it is with a sense of unease that even the simplest comparisons are made. Second, the "sensitive areas" referred to in this case can in fact be entered with minimal damage, either short- or long-term, and it is the desire to promote a wilderness status for the Wildlife Range which creates the degree of "sensitivity" that has colored this case. Although the Chugach Forest and Prince William Sound have similar "sensitive" qualities, no effort to elevate the latter's status has occurred. Alcan's claim to environmental superiority solely because it would avoid sensitive areas is entitled to weight, but hardly the weight which Alcan, the Conservation Intervenors, or the DOI and Staff environmental witnesses would attribute to it.

An appreciation of the full environmental impact cannot end by considering the effects solely in Alaska. The Alcan proposal would build two pipelines to bring the same U.S. and Canadian gas to market which Arctic Gas proposes to do in one pipeline. About 1500 extra miles will be built to Zama Lake, Alberta, but, Alcan insists, only through existing corridors. 1/ See map attached to Appendix A. Questions posed to the environ-

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1/ From Prudhoe Bay to Zama Lake, Alberta, Arctic Gas will build about 1160 miles of new pipeline (ST-32, ST-52, as adjusted for cross-delta alignment). Alcan and Maple Leaf will build about 2684 miles of new pipeline to Zama Lake and Fort Nelson, British Columbia (ST-32, ST-52).

mental witnesses for DOI and Staff elicited almost uniformly the same response; it is better to cross the Wildlife Range with appropriate safeguards than to build two separate lines through thousands of extra miles through North America.

El Paso, which at least has no Canadian ties in this section claims that whether Canada ever builds a pipeline to connect Mackenzie Delta gas is not of prime interest to it, Alcan is the sponsor of the Maple Leaf project to build such a pipeline. It is a testimony to man's ability to compartmentalize the human mind to argue, as Alcan does, that the only environmental aspects of this case are those in Alaska and that the only environmental concerns of the United States are those that are in U.S. territory. 1/ While parts of Alcan's project admittedly are on some lands near other construction, whether pipeline or highway, the combined adverse impact of Alcan's facilities far outweighs any environmental savings to the U.S. from building these separate facilities. Both the U.S. and Canada pay the same environmental cost under Alcan's proposal. Under the Arctic Gas proposal, the U.S. environmental cost (albeit by going through the Wildlife Range), becomes less significant and the Canadian impact remains, at worst, the same. Canada is eventually going to exploit frontier energy.

Alcan argues that the same consideration is true of El Paso if it is true of Alcan. It is so found. The overall environmental advantages to the U.S. and Canada in building a single line far exceed an LNG-ship-LNG project at the end of an 800-mile pipeline and an additional 1,000 miles of pipeline for Maple Leaf.

These findings, of course, reflect only one aspect of the total picture. The environmental considerations are only one part of the public interest equation, and "all other things" are clearly not equal among the applicants in those other areas to an even greater degree than the inequality here.

1/ The United States is a party to any number of treaties and agreements attesting to its concern for the environment outside the territorial U.S. See, *supra*, Cross-Delta discussion.

F. Alternatives

Many of the alternatives affecting a particular site selection or specific routing of a pipeline have been addressed, e.g., LNG plant siting in Alaska and California, routing along the Alyeskan rights-of-way, base-case routing for El Paso, the prime Arctic Gas route across the Mackenzie Delta and the western leg. The need for natural gas as opposed to alternative fuels will be discussed in other sections of the Initial Decision. See the Marketability and Finance sections. This section addresses itself to the significant remaining alternative methods of transportation as well as alternative routings not heretofore discussed.

1. Alternative Transportation Methods

The applications and environmental impact statements address a large number of possible, although not necessarily practical, alternative methods of transportation. Among those considered for LNG were giant submarines, airplanes, ice-breaking tankers to navigate the Arctic Ocean in the winter, lighter-than-air airships, conventional railways, and monorail. None of these alternatives were supported by any evidence which showed that they were technically viable, much less economically feasible. A dense-phase pipeline was analyzed and rejected because it would require a plant on the North Slope (similar to the proposed LNG facility) and cryogenic pipeline technology not in existence.

The conversion of natural gas to methanol (a liquid alcohol) before transport was also examined. The scheme would convert natural gas to methanol in Alaska and transport it to the lower 48 states from the North Slope by conventional pipeline, by submarine or by ice-breaking tanker or from southern Alaska by tanker. Then, the methanol would either be converted to "synthetic natural gas" or used directly as chemical feedstock. 1/ The conclusion reached was that, while methanol production and transport might be technically viable, several severe drawbacks make it impractical. First, methanol conversion is costly. According to the FEIS of DOI, the total common-destination capital cost would be almost 1.5 times that of the Arctic Gas proposal, and the total operating cost would be three times greater (ST-25, p. 124).

1/ Since the object is to bring natural gas to market, the use of methanol in the lower 48 states was not extensively investigated.

Second, methanol conversion requires large amounts of fresh water. Estimates range from 125 gallons to 300 gallons of water required for every ton of methanol produced (ST-25, p. 122). Third, the methanol scheme is extremely energy-inefficient. The chemical conversion of natural gas to methanol and the possible reconversion to synthetic natural gas requires large amounts of energy. In sum, from both a logistics and cost perspective methanol is not a feasible alternative at this time for this gas supply.

2. Alternative Routes

Of those routes not yet discussed, there are two routes along the coast which Arctic Gas considered and rejected before selecing its prime route. The first is an offshore pipeline; however, all evidence indicates that the technology to protect the pipeline from sea-ice scour--which can gouge out grooves measured in the tens of feet deep in the ocean bottom--does not exist. In addition, the cost would be prohibitive and winter repairs nigh impossible. The second route would be on land but just inside the shoreline. This route would impact many more shore birds, but would have the advantage of avoiding the more inland coastal portion of the Wildlife Range. This route was ultimately rejected because its potential adverse effect on bird life far outweighed the environmental impact of the prime route. There has been no substantial support for this route, although several of the witnesses thought it had merit. An "interior" Arctic Gas route would have to cross the Brooks Range by going south before east and would cross significant wildlife habitat. 1/ It was not seriously supported by anyone. None of these routes are suitable, and all are found inferior to the Arctic Gas prime route.

3. Fairbanks Alternative

The Fairbanks alternative, as described in the Staff FEIS (ST-18,I-A7), is identical to the Alcan route until it reaches Fort Nelson, British Columbia (although it is hypothesized as a 48-inch, high-pressure system). Form Fort Nelson, it continues southeasterly, rejoining the Arctic Gas prime route at Windfall, Alberta. At this point, the line parallels the Alberta Gas Trunkline system to Empress on the Alberta-Saskatchewan border. From here, the route follows the "Moosejaw-Brandon-River River" corridor, paralleling the Trans-Canada Pipeline Ltd. system to a point along the Red River at Emerson, Manitoba, where it enters the United States and proceeds south along the Midwestern Gas Transmission Company corridor to Ada, Minnesota, and Kankakee, Illinois. If Mackenzie Delta reserves are to be moved through

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1/ For an extended discussion of the interior route, see ST-26,502 *et seq*.

this system, a 756-mile pipeline from Richards Island to Whitehorse, Yukon Territory, must be built--the so-called "Richards Island Lateral." The Fairbanks alternative, without the Richards Island Lateral, remains the preferred route of the Commission's environmental Staff. In its Position Brief, Staff states that the Fairbanks alternative with the Richards Island Lateral is environmentally superior to the Arctic Gas, Alcan or El Paso systems. However, it notes that Arctic Gas is environmentally preferable to the Fairbanks alternative with a Maple Leaf-type pipeline system down the Mackenzie Valley (Staff Position Brief, 29). Staff cautions, however, that "The above conclusions do not consider economic feasibility" (Staff Position Brief, 29).

The final position of Staff concerning the Fairbanks alternative, taking all factors into consideration, is stated in the Economics section of its Postiion Brief, at 27:

> The cost of a 48-inch diameter pipeline from Prudhoe Bay, through Fairbanks, along the Alcan Highway (including south of Fort Nelson) to Caroline and Empress, Alberta would be in the neighborhood of $6.5 billion (Exhibit ST-31). The facilities currently proposed by Arctic Gas from Empress to Dwight, Illinois are estimated at $1.3 billion (Exhibits AA-35 and 71). A Richards Island Lateral with a capacity of 2.4 Bcf/d would cost approximately in excess of $2 billion; thus, the total cost of the environmentally preferable alternative would be in the range of $10 billion, more than 16% greater than the Arctic Gas project as proposed. In view of this, it is still Staff's position that such an alternative is not economically viable when compared with the Arctic Gas project.

It is concluded that the Fairbanks alternative has had insufficient environmental and geotechnical support on the record to overcome its obvious and substantial economic disadvantages. The present Fairbanks routing is similar in some respects to the proposed Alcan project. That is, it might become acceptable with further site-specific studies and engineering analyses. However, to date, environmental studies of the route have been scant (149/23,000), and costs and engineering factors have not been considered (144/23,552).

The Staff environmental witnesses, moreover, gave only superficial consideration to environmental impact of the Richards Island Lateral (144/23,608-609). Indeed, differences of opinion still exist even on the environmental superiority of the Fairbanks alternative. While the environmental Staff of the FPC concluded (by a 3-to-1 "vote") that the Fairbanks alternative with a Richards Island Lateral is superior to the Arctic Gas prime route, three out of four of the Arctic Gas environmental consultants disagreed. Witnesses McCart (fish), Jakimchuk (mammals) and Dabbs (vegetation) all preferred the Arctic Gas alignment. Jakimchuk noted, for example, that river valleys paralleled by the Fairbanks routing are the foci of larger populations of mammals and the removal of habitat here would have heightened significance (172/28,224-226). Of course, it must be remembered that the Fairbanks alternative with a Richards Island Lateral is more than a thousand miles longer than the Arctic Gas route (ST-32). 1/

Even if one were to accept, *arguendo*, that the Fairbanks alternative is environmentally preferable, it is simply not economically viable. As Staff suggests in its Position Brief, *supra*, and ST-32, the Fairbanks alternative with a Richards Island Lateral is almost $3 billion more expensive than the comparable Arctic Gas project.

Furthermore, Staff witnesses David Lathom and James Kiely, Jr. testified that, if a Fairbanks alternative is hypothesized, the only realistic option available to the Canadians would be to certificate the Maple Leaf project and not the Richards Island Lateral. Although the Fairbanks route with a Richards Island Lateral would be somewhat less expensive than a Fairbanks route plus the Maple Leaf system, the former "combination would require the Canadian consumer to bear the burden of a capital cost of more than $3 billion for a jointly owned facility when an all Canadian project is being proposed for approximately the same capital cost" (141/22,085). Clearly, a Fairbanks alternative routing combined with a Maple Leaf system is inferior economically and financially to the Arctic Gas project. In addition, the Staff has conceded such a routing would be environmentally inferior, *supra*.

1/ Canadian gas, as a matter of fact, would move south before moving east, as well as moving almost twice the distance.

The Moosejaw-Brandon-Red River corridor is the environmental Staff's preferred route east of Empress. However, the DOI witnesses who conceived this route conceded it was only "conceptual" (136/21,823) and was planned with no consideration of environmental impact in Canada (136/21,819). Thus, the alternative route is allegedly 343 miles shorter than the corresponding Northern Border segment. In reality, this includes only mileage within the United States, and an examination of the total mileage in both the United States and Canada reveals that the Red River route is 70 miles longer than the Northen Border route (170/27,876). The alternative is also designed to avoid the pothole region in the United States. However, Northern Border witness Strobel testified that the Red River routing traverses areas in Canada where potholes are more numerous, occur in higher density, and have a higher habitat value. Other stated advantages of the alternative route have either been mooted by the modifications prescribed supra, are available options for either routing, or fail to outweigh the disadvantages of the routing (NB-34).

VII

SOCIO-ECONOMICS

The parties all agree that the National Environmental Policy Act requires discussion and analysis of the socio-economic impacts of major federal actions. Pursuant to this requirement, both the DOI EIS (ST-26) and the FPC EIS (ST-18) attempt to describe and quantify, to some extent, the various impacts that would result from the alternative proposals. Arctic Gas, El Paso, Alcan and the State of Alaska also introduced studies examining the socio-economic impacts of the various projects. 1/

As far as the United States is concerned, the primary socio-economic effects which are definable at all are concentrated in the State of Alaska. 2/ Since the overwhelming benefit to the State, regardless of the pipeline certificated, will be royalty gas payments and severance taxes, the issue really concerns those additional benefits or costs to the State that might flow from one pipeline project more than from another. On the practical side, the stakes are additional jobs and tax revenues versus pressure from inmigration on public and private goods and services. No one questions that socio-economic factors should be considered in this proceeding. However, as discussed *infra*, there is a distinction between the ability of the Commission to infer and weigh benefits on the one hand, and, on the other hand, to weigh the benefits against possible costs to a state or region to determine whether a grant of a certificate is in the public interest.

A. Arguments of the Parties

The State of Alaska argues prefatorily that one must view its economy as akin to that of an undeveloped nation, dependent in large measure on extractive industries with the only large and stable industry being the federal and state governments. Alaska

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1/ DOI, Staff and Alcan used econometric models developed by the Institute for Social Economic and Government Research as part of the Man in the Arctic Program (MAP). El Paso's socio-economic report was based, *inter alia*, on projections of the Human Resources Planning Institute and the Urban and Rural Systems Associates (URSA). Arctic Gas based its conclusions on an analysis done by URSA, retained as its socio-economic consultants. The State of Alaska's projections were based on revenue-cost analyses by Alaskan state officials.

2/ The NNEB discussion, *infra*, addresses itself to overall U.S. socio-economic impacts.

believes the El Paso proposal will create the greatest net benefit to the State: added employment, increased tax revenues, additional development, and maximum opportunity for intrastate use of royalty gas. Citing the Alaskan Statehood Act's legislative history as promoting the independence and growth of the Alaskan economy, it argues that it is the will of Congress to encourage development within the State and that this can only occur if there is a trans-Alaska (El Paso or Alcan) pipeline. Alaska argues that nothing should be done to inhibit or foreclose future use of the State's royalty gas. It wishes, therefore, to foster internal development of industry that it believes is desperately needed to broaden Alaska's economic base and reduce its dependence on the rest of the country. In the State's own words, it prefers El Paso because (Alaska Initial Socio-Economic Brief, 12):

> The El Paso project would create far more employment within the State, would increase population along the southern coast of Alaska to the extent that that portion of the State at least would have a private economy of reasonable size, and would provide far greater State and municipal revenues in order that the governmental units can cope with the socio-economic costs that are certain to result from any of the projects. When the benefits of the El Paso project so far outweigh any of its costs, and when its net socio-economic benefits would so far exceed those of the Arctic Gas Projects the State cannot conceive of refusing to grant the El Paso project a preference on socio-economic grounds....

El Paso, of course, asserts that the preference of the State of Alaska should be given great weight on socio-economic issues. The "value judgment" of the State, it is argued, provides the most meaningful evaluation of impacts. Moreover, El Paso implies that although its project will result in greater overall impacts on Alaska, the net effect will be more beneficial to the State than the other projects. El Paso states that it will have positive effects on population, employment, personal income and public service revenues and notes that El Paso will be in a position to ease the adjustments necessary after Alyeska construction. Finally, El Paso echoes the State's desire to have the natural gas available for residential and industrial use along the route in Alaska.

Arctic Gas argues that its project is preferable on socio-economic grounds, since it will produce substantially the same benefits as the other projects, but fewer costs. 1/ It states that the overriding benefits to Alaska from all three projects are severance taxes and royalty payments, which each project will equally assure. Compared to these benefits, it alleges, the other benefits to Alaska--such as employment and other taxes--will be miniscule and transitory. Arctic Gas contends that neither the Alcan nor the El Paso project will alleviate the post-Alyeska downturn, since there will be a lag between the end of Alyeska construction and the commencement of gas pipeline construction. In fact, Arctic Gas believes that either of the two proposed gas lines will produce another large-scale economic downturn after it is completed. Finally, Arctic Gas states that the prospects for significant intrastate use of royalty gas are dim, given the economic realities of future Alaskan industry development. At the same time, Arctic Gas argues that the social and economic costs to Alaska will be substantially less if its project is certificated. Arctic Gas associates numerous harms with increased in-migration and asserts that its shorter, inaccessible route will attract very few newcomers.

Alcan does not make any net benefit comparisons with the other projects. Rather, it simply asserts that the total socio-economic impact on Alaska from its project would be greater than Arctic Gas and less than El Paso.

Staff states that the record does not permit a "bottom line" comparison of net benefits to the State from alternative proposals. All that can be ascertained from the record,it asserts, is that total impacts to Alaska are greatest from El Paso and least from Arctic Gas. Staff argues that "Conclusions about net benefit rankings should be based on a benefit-cost analysis using methods normally applied by economists in benefit-cost studies" (Staff Reply Socio-Economic Brief, 2),This, according to the Staff, is missing from this case. Staff concludes that all three projects would provide a net benefit to Alaska. Moreover, it argues that

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1/ On a percentage of return basis, this is irrefutable. Revenue of $100 with only $10 cost is a better return than $200 revenue and $100 cost, even though in the latter case, the net is $10 greater than the former.

the intrastate use of royalty gas is a beneficial, although speculative factor, but that the Arctic Gas project will not preclude such usage since gas exchange agreements are possible. 1/ Finally, Staff rejects Alaska's suggestion that the Alaska Natural Gas Transportation Act of 1976 requires a trans-Alaska routing. It sees such an interpretation as inconsistent with both the statutory intent and the avowed neutrality of the Act.

B. Royalty Payments and Severance Taxes

The State of Alaska will reap enormous socio-economic benefits from gas pipeline construction, regardless of which project is certificated. While all three pipelines will create benefits and costs to the State, it remains an uncontroverted and undeniable fact that a huge net benefit will be harvested by the production of the gas alone, and this will far outweigh any costs to the State occurring from any pipeline construction. Thus, all three pipelines are acceptable as far as socio-economics factors are concerned and, if this case did not involve competitive applications, the inquiry would end here.

Quantification of these overall benefits is not difficult. The most substantial economic benefits to the State will come from hydrocarbon severance taxes and royalty payments. It is obvious that these sums are so large as to overwhelm any associated costs of the project once operations begin. Assuming only a 2.25 Bcf/d rate of flow from the Prudhoe field and a wellhead price for gas of $1.00 per Mcf, Alaska's 12.5 percent royalty interest and current 4 percent severance tax will net the State $135.5 million a year. 2/ It is reasonable to conclude, as Staff and Arctic Gas argue, that the State will receive several billion dollars from severance taxes and royalties over the next several decades (Arctic Gas Socio-Economic Brief, 11).

1/ Under an exchange agreement, a company having gas elsewhere in Alaska could swap that gas for Prudhoe Bay royalty gas.

2/ This is primarily associated gas produced with and at the same time as oil. The state's revenue from oil will be many times the millions in revenue it receives for the gas. Governor Hammond testified that there has recently been a proposal to increase the severance tax rate to 10 percent. This would raise the revenue figure cited in the text by about $50 million (96/14,664).

Once the fact is accepted that all the projects will produce approximately the same revenues in severance taxes and royalties, other economic variables become somewhat less significant. The bottom line for the State's development is the manner in which the State expends the billions in revenues. It is those state policies which will determine the ultimate socio-economic effect of the project.

C. Other Socio-Economic Factors

Those parties arguing various socio-economic impacts focused on population, employment, gross state product, personal income, and government revenues and expenditures. There is no dispute that the greatest impacts on the State, whether beneficial or detrimental, will come from El Paso, followed by Alcan and Arctic Gas. However, unlike royalties and severance taxes, these impacts are difficult to quantify and place in their appropriate places in a cost-benefit analysis.

The evidence does not permit a useful or valid bottom-line net benefit calculation for each project. In fact, the only factors subject to a "cost-benefit" quantification were public revenues versus public expenditures, but the inputs into the equation were often arbitrary or based on unsupportable assumptions. Even assuming the inputs were not arbitrary, the analysis itself is incomplete (perhaps necessarily), since only direct, foreseeable costs and expenditures were included. The effects of some socio-economic impacts, like inmigration, have unpredictable long-range impacts on the public treasury and other influences on Alaskan society which are simply not quantifiable given the limitation of economic modeling. For these reasons, a conclusion on which project will create the greatest net benefit for the State now or 20 years from now cannot be reached. The best that can be said is that while the State will benefit from all three projects, the comparative net benefit of each project from factors other than severance taxes and royalties remains uncertain. The following discussion attempts to put some of these impacts in perspective.

1. Employment

El Paso and Alcan will create greater impacts to the State because of the amount of construction and facilities they will bring to Alaska. While either route will create more jobs than Arctic Gas, the number of direct jobs created is not substantial, and long-term employment opportunities are few. Alcan, employing the most workers at one time, will reach a maximum peak employment of only 5,915, compared to 5,200 for El Paso and 2,400 for Arctic Gas (See comparison in Arctic Gas Initial Socio-Economic Brief, p. 12). Given the magnitude of investment, the maintenance and operation crews for the transportation system of all three projects are small. The total employment of the El Paso LNG plant is only 350.

It is now nearly certain that the gas pipeline construction will not ease the high unemployment expected after Alyeska construction. No gas pipeline will be built until several years after Alyeska's completion. While several parties calculate total induced employment by estimating an appropriate "multiplier," the selection of the multiplier is so arbitrary as to be almost useless. El Paso uses a multiplier of 35.83 to predict that 21,000 total jobs will be created from about 600 direct pipeline jobs in 1983. But El Paso witness Robert Mott testified that the 21,000 figure is the result of a cumulative economic effect, an unspecified part of which can be ascribed to exogenous factors. In fact, Mott testified that there is an error factor of at least 10 to 20 percent (63/96,452). Arctic Gas suggests that only a 1.5 multiplier should be employed, which is the most common multiplier used in Alaska.

2. Population and Local Communities

As with employment, the Alcan and El Paso routes will produce greater increases in permanent population than Arctic Gas. Merely to say that the projected increases suggested by the parties vary is an understatement. El Paso estimates a population increase from its project of 57,000 by 1980, while Staff estimates 24,000 and the State of Alaska 46,000. 1/

Unlike the rise in employment, population increase is a mixed blessing to the State of Alaska. The extent to which it creates revenues through personal income taxes and creates costs through public expenditures is discussed later in this section. There are numerous factors, however, many deleterious to the State, which cannot be factored into a public cost-expenditure quantification to arrive at bottom-line figures. Nevertheless, it is clear that the trans-Alaska routes, resulting in greater population increases, will create the greatest employment disturbances.

Unemployment may result from the expected large inmigration of people looking for jobs but only a limited number of jobs avail-

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1/ In comparison, Staff estimates a population increase for Arctic Gas of 4,300 by 1980.

able. Historically, sudden large-scale increases in employment opportunity in Alaska have increased the rate of unemployment because more people come to the State seeking jobs than find jobs. In the first year of Alyeska construction, for example, the unemployment rate rose, as did welfare and crime. No one put on this record that a solution to the inmigration phenomenon had been found, and El Paso and Alcan will repeat the Alyeska inmigration pattern.

An understanding of the inmigration pattern clarifies the difficulty of resolving it. Many of the workers coming into the State are without jobs, are likely to be unskilled and do not heed warnings that there are few jobs available. 1/ The higher unemployment rate creates costs, both in public services required and private family stability. Second, the population increase causes shortages of public and private goods, services and housing, and results in inflation. Alaska is unique in that almost all goods used there must come from the lower 48 states, and, therefore, existing severe supply shortages may be exacerbated. Furthermore, the MAP model used by Staff portrays a steady economic growth rate with the Arctic Gas project because of its more limited attraction of inmigrants. It shows that Alcan and El Paso will cause rapid economic growth during construction, followed by a collapse, and then another more moderate increase.

Finally, inmigration may result in unique socio-economic burdens on various local communities in Alaska. On the basis of relative growth, Cordova, 13 miles southeast of Gravina Point, will suffer the most change with the El Paso project. Because of LNG plant construction and operation, the population is expected to fluctuate from 2,400 in 1977 to 9,100 in 1979 to 4,100 in 1982. As Staff notes, the character of the town itself may change from a fishing village to an industrial town. 2/ The State of Alaska concedes that the socio-economic costs to small communities will be greatest for the El Paso project. The Arctic Gas route will impact Kaktovik, and the Alcan project will impact small communities along the Alcan Highway. However, these communities will not experience significant increases in population or demands for services. With the Arctic Gas project, the short winter construction concept will lessen the impact on Kaktovik.

1/ The jobs which are available are high paying, and the reward of landing one of these jobs outweighs the risk of unemployment.

2/ It may change in any case, since oil discoveries in Prince William Sound or the Gulf of Alaska would require that Cordova become a major supply depot.

As indicated above, both Arctic Gas and El Paso cite the support their projects have received from the citizens of Kaktovik and Cordova, respectively. Curiously, El Paso (supported by the State) urges that the opinions of Cordova "be weighted heavily" but warns that "the citizens of Kaktovik may not know what they are bargaining for when they urge the selection of Arctic Gas" (El Paso Initial Socio-Econimic Brief, 11). As previously stated, the preferences expressed by the citizens of Kaktovik and Cordova have been considered as have those of the State of Alaska.

3. <u>Indigenous Residents</u>

The impact on local communities may be especially important if native populations are involved. 1/ Many of the native communities have subsistence or mixed cash-subsistence economies. Staff defined subsistence as follows:

> ...the use of a natural resource by a person or group to meet personal needs in terms of life essentials such as food, clothing and shelter. It may be contrasted with commercial use of natural resources or non-essential use of such as for recreation (ST-18,C74).

The perceived threat to native communities seems to be threefold: depletion of wildlife for subsistence hunting, introduction of cash into native economies (partly as a result of increased native employment), and changes in cultural values. Staff asserts that all three pipeline proposals will, to some extent, affect the Alaskan native lifestyle. Arctic Gas will impact the native village of Kaktovik (population 130); El Paso and Alcan will have incremental impacts on native communities already affected by Alyeska; and Alcan will impact native villages from Delta Junction to the Yukon border. Staff argues that "the El Paso and Alcan proposals would affect the Alaskan natives' lifestyle more than the Arctic Gas project would; however, the events of the last few years in Alaska have already changed native living significantly and will continue to do so, with or without any of the natural gas pipelines" (Staff Initial Socio-Economic Brief, 2).

1/ The term "native" is used here to describe Eskimos, Indians, and Aleuts. So-called "Alaskans" are discussed <u>infra</u>. In large measure, the discussion here is applicable also to the native communities in Canada. See ST-27.

It is important to realize that many native communities, including Kaktovik, have long had mixed cash-subsistence economies. The more recent use of cash has been encouraged by increased "urbanization" of natives, implementation of the Alaskan Native Claims Settlement Act, and the employment opportunities created by Alyeska. The increased dependence on a cash economy is likely to continue, regardless of which pipeline is certificated. However, the encroachment of a cash market economy does not have to be accompanied by the disappearance of native cultural identity and values. Traditional culture has been combined with a cash economy for many years. Arctic Gas witness Joseph Henry Weinstein discribed this interrelationship:

> Subsistence living as it applies to the North Slope and all of Alaska is a very complex concept. However, subsistence for Alaska Natives does not mean either a primitive barter economy or a lifestyle devoid of modern conveniences. It is a life combining traditional cultural beliefs and actions with the pressures and products of a modern cash economy. Cash is an integral part of that lifestyle, enabling the individual Alaska Native to purchase much of the equipment required to continue subsistence activities (175/28,956).

Careful project design and communication with local planning agencies can continue to preserve the traditional native lifestyle. Moreover, measures to mitigate impacts on wildlife, discussed elsewhere in this Decision, will protect the objects of native hunting, fishing and trapping. Arctic Gas witness Weinstein testified that even native subsistence hunting is now dependent on cash economies. That is, residents are dependent upon cash to purchase articles now necessary for subsistence activities, including snowmobiles, aluminum boats, high-powered rifles, and outboard motors. It is interesting to note that snowmobiles have completely replaced dog teams in Kaktovik. As a result, although each pipeline project may help to increase the rate by which native communities adopt cash economies, it will not be these projects which diminish the native cultural values and lifestyles.

There is simply no evidence to support the numerous attempts to relate specific impacts upon the native communities to the individual projects under consideration here. Absent direct physical contact--such as going directly through a native village--the contacts will be minimal and for the most part will be the result of planned affirmative policies such as preferential hiring. Second, the changes that are occuring will continue to occur even if these projects are never built. Native culture as it exists today represents an amalgam of 200 years of increasingly close contact with Euro-American culture and a continued movement from a semi-nomadic to a money economy. It is also readily apparent that the protection of the "subsistence economy," which is almost impossible to define because of the total confusion with "subsistence cultural values," must first be addressed by the political process. 1/

There is another facet which must be discussed. The native communities, particularly in the North Slope Borough which has local taxing power over the Prudhoe Bay Field, are just now expanding their governmental services. In part because of the Native Claims Settlement Act, the Borough is proceeding to finance capital improvements in the several native communities on the North Slope. The infusion of substantial capital and expansion of services in relatively small and booming communities represent the most significant changes in the native communities. The expectations of the native population along the Alcan route are not substantially different. With the settlement being presently negotiated by the Canadians and with the heightened native participation in this process, the same changes can, in all likelihood, be expected for the Canadian portions of the projects. In sum, the affect of any of these projects on the natives or native communities is not measurable, but to the extent it can be recognized, it is probably de minimis.

4. Public Revenues and Expenditures

Not surprisingly, the Arctic Gas route will have a lesser impact on governmental receipts and outlays than the other two projects. The State of Alaska compared public revenues and expenditures for the El Paso and Arctic Gas projects. Revenues included royalties, severance taxes, property taxes, and personal and corporate income taxes. Expenditures were computed by multiplying $1,630 (the per capita cost of state government in Alaska in 1975) by the induced population expansion. It was determined that the El Paso project has a net present value $123,315,000 greater than Arctic Gas (ALA-27). While the figures derived by the States are open to serious question, it appears that El Paso will have a somewhat greater net revenue benefit than the other projects.

1/ An urban native may, for cultural reasons, have to shoot a seal to maintain status in an Eskimo community (198/33,779). Similarly, extending requirements of child education could change certain migration patterns of otherwise nomadic peoples.

However, several cautions must be noted. First, no allowance was made in the Alaska analysis for the economic drain of workers sending their paychecks out-of-state, despite the knowledge that this is done by a large percentage of construction workers. Second, the population estimates used in ALA-27 are lower than other population estimates made by the State. Third, it was assumed that state services and other costs will remain the same in the future as they have in the past. Fourth, the net revenue results reached in ALA-27 are considerably different than those reached by El Paso, emphasizing the difficulties involved in this type of calculation. El Paso concluded that during construction, the State would have a net revenue benefit of $68 million, and during operations, $170 million. The State concluded that it would suffer a net deficit during the construction years and would average about $105 million net revenue benefits during operations from the El Paso project. The State's estimate of revenues is substantially lower than the El Paso estimate, and Alaska's estimate of costs is greater. Similarly, the cost estimate of the State during construction is much lower than that of the FPC FEIS.

Arctic Gas asserts that any benefits accruing to the State, in addition to royalty payments and severance taxes, are insignificant. They are not. While property, personal and corporate income taxes are certainly much smaller than the royalty and severance taxes, property taxes alone may be sizable. Based on an annual tax rate of 20 mills per dollar (i.e., 2 percent), the FPC FEIS estimates that during operations, Arctic Gas will pay $10 million annually in property taxes, while El Paso will pay $40 million if the LNG plant remains outside the tax base and $72 million if the LNG facility becomes taxable. These figures are probably inflated, since they apparently do not assume depreciation of the taxable base (Arctic Gas Initial Socio-Economic Brief, 14). Alaska's calculations, which do assume depreciation, still show sizable advantages resulting from the additional taxes. Alaska estimates annual cash inflows during El Paso operations between 1983 and 1995 to be an average of $54 million greater than those of Arctic Gas. Most of this additional amount is comprised of property tax advantages derived by the State from the El Paso project. This total accounts for the fact that El Paso's average annual net revenue benefit is $105 million, while Arctic Gas' is $68 million. (El Paso's average annual cash outflows are $17 million greater than Arctic Gas' (ALA-27, Tables 3,7).)

Arctic Gas also argues that there will be a lag between the increase in the taxable property base and the increase in property taxes collected. Furthermore, the increase in property taxes may accrue to a different jurisdiction than the one which experiences a newly expanded population. Gravina Point, for example, is presently not in the property tax jurisdiction of Cordova, which would be required to expend resources associated with the LNG plant. These factors, while affecting to some extent the efficacy of property taxes to compensate for current expenditures, do not support the dismissal of property taxes altogether in evaluating socio-economic impact.

D. Intrastate Use of Royalty Gas

Alaska argues that, in addition to favorable impacts on employment, population, gross state product and net government revenues, the El Paso project will allow and in fact encourage industrial development in central Alaska. The State, eager to shed its dependence on the lower 48 states and its unstable, boom-or-bust economy, envisions the development of mineral reduction, fertilizer, cement, and petrochemical industries that can use the royalty share of the Prudhoe gas. 1/ Langhorne Motley, Commissioner or Commerce and Economic Development for the State, testified to the importance of this development and the potential for enticing industry into the State once the gas pipeline is completed. However, no cost-benefit analysis was performed concerning the intrastate vs. interstate use of royalty gas. On the whole, moreover, he was unable to detail concrete examples of discussions with prospective industrial users, and the State's use of Alaskan gas remains speculative, at best. The fact is that Cook Inlet gas supplies did not spur any substantial development, although Alaska argues that development of Cook Inlet gas involves piecemeal discoveries at a time when there were sufficient supplies of low-cost gas in the lower 48 states.

It is undeniable that the present economic realities of Alaska do not encourage industrial development there: high construction and labor costs resulting in high capital cost plant facilities, significant transportation costs, and primary markets in the lower 48 states. There is also a serious question whether the State's anticipated use of gas in Alaska will be compatible with federal natural gas end-use policy or environment sensitivities. Finally, if the State does use its full royalty interest intrastate, the result could be increased lower-48 consumer prices

1/ Guy Martin, Commissioner of Natural Resources for Alaska, indicated that the State would also benefit from a gas liquids removal plant built in Alaska, if El Paso was certificated.

because of the underutilized El Paso facilities. In sum, there are so many uncertainties involved in intrastate use of royalty gas that no findings that it will occur are warranted at this time. Moreover, if it did occur, it would more likely occur around Cook Inlet where there are gas supplies which could be used for the purpose. 1/

E. Public Interest Requirements

The State of Alaska has made a value judgment that the increased development and socio-economic impact on the State resulting from a Trans-Alaska project, and El Paso in particular, is in its best interest. The various econometric models and analyses, however, verify only that all projects will benefit the State and that El Paso will impact the State the most. As already stated, Alaska's views are entitled to substantial weight even where the evidentiary showing may be somewhat ambiguous. But, even if a determination that it would benefit Alaska to have one project rather than another were made, the Natural Gas Act does not permit this Commission to certificate a project which will benefit one area of the country to the detriment of another.

The great bulk, if not all, of the Prudhoe Bay gas will be marketed in the contiguous states. Thus, under the tariffs proposed in this proceeding (or any other tariff appropriate to the purpose), consumers in the lower 48 states will be required to pay rates which will recover substantially all of the costs of the particular transportation system to be authorized, including costs incidental to any terms and conditions imposed on the grant.

While Congress has the power within constitutional limits to direct that certain actions be taken solely on the basis of favoring the economic condition of a particular state or region at the expense of others, it has not expressed any intention that the Commission, in the performance of its duties under the Natural Gas Act, create such preferences as those claimed here by the

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1/ Governor Hammond testified that an oil refinery is planned for the Fairbanks area. Thus, there will be energy supplies available to central Alaska, even absent a trans-Alaska pipeline (96/14,675). Moreover, it should be noted that the use of gas for residential purposes in a cold climate such as Alaska's might be economically impractical, given the necessarily high fixed costs involved and the poor load factor.

State of Alaska. The Commission has historically, with court approval, declined to do so, and nothing in the 1976 Act requires a change in that policy. 1/

Thus, the Commission has held that the economic ills of a particular area or region are not a valid consideration in determining pipeline rates and that costs may not be shifted from one region to another to affect local economic conditions. Michigan Wisconsin Pipe Line Company, 34 FPC 1188, 1190 (1965). Further, in establishing ceiling rates for interstate sales of gas by producers, it was judicially determined that the Commission properly declined to accede to pricing arguments based solely upon the particular economic interests of the States of Texas and New Mexico. Skelly Oil Company v F.P.C., 375 F.2d 6, 18(10th Cir., 1967); reversed on other grounds, 390 U.S. 747(1968). See also F.P.C. v Hope Natural Gas Company 320 U.S. 591,607-614, holding that nothing in the Natural Gas Act intimates that high prices should be maintained so that "the producing states obtain indirect benefits."

The State does not argue, of course, that specific additional money be spent in the State or that the transportation rates be raised as a condition of the grant. 1/ However, giving additional weight to the all-Alaskan proposal and giving less weight to the trans-Canada proposals has the same effect. The major benefits the State derives from the El Paso proposal are the jobs and tax base of a multibillion dollar, 800-mile pipeline and LNG facilities, the liquid removal plant which would be built by the producers in Alaska (probably at Gravina Point), the additional industry which would settle in the State to utilize cheap energy, and the multiplier effect upon the State's economy by all of the above. But the result of giving disproportionate weight to these considerations and choosing an all-Alaskan route even if more expensive, rather than basing the decision on an analysis of costs and benefits which redound to all consumers, is no different than that already rejected by the Commission and the courts.

1/ In his recent initial decision in Virginia Electric and Power Company, Project 2716 (September 20, 1976), Judge Benkin approved certain proposals that Vepco contribute funds for amelioration of defined socio-economic impacts. Assuming the statutory standard of that case is the same as here, it is of no precedential value, in that Vepco volunteered such an accommodation and the only justifiable issue was the nature and level of contribution. It is noted, moreover, that the county obtaining the contribution had no direct connection or tax base with the project which was being built in a neighboring county.

If there exists an alternative system which better meets the overall public interest, it would be contrary to the Commission's accepted regulatory role under the Natural Gas Act to select a particular transportation system at the behest of the State of Alaska in order to accord substantial economic benefits to the State. Similarly, the Commission should not condition the approval of any transportation system upon the expenditure in Alaska's interest of vast sums resulting in higher rates over and above the amounts necessary for an operationally adequate and environmentally acceptable system.

F. The "Hire Alaskan" Statute

One other matter must be discussed here. Questions arose from time to time in the hearing concerning certain hiring practices which might give preference to "Alaskans" over other citizens of the United States. 1/ As reported by the court, the state statute requires, that

> all oil and gas leases, easements or right-of-way permits for oil or gas pipeline purposes, unitization agreements or any renegotiation of any of the preceding to which the State is a party provisions requiring the lessee to comply with application laws and regulations with regard to hire of Alaska residents. The Commissioner shall include a provision requiring the hiring of qualified Alaska residents... AS 38.40.030.

The court also quotes the statute defining an "Alaskan" as a person who:

> (1) except for brief intervals or military service has been physically present in the state for a period of one year immediately prior to the time he enters into a contract of employment; and
>
> (2) maintains a place of residence within the state; and

1/ According to counsel for the State of Alaska, some suits filed by persons alleging discrimination on this basis under Alyeska's "Alaskan Hire" program have been settled out-of-court. A recent decision by a State Superior Court Judge in Alaska upholding the Alaska Statute as constitutional was submitted for the record (ALA 32). Hicklin v. Orbeck, Alaska Superior Ct. No. 76-3300, entered July 21, 1976.

(3) has established a residency for voting purposes within the state; and

(4) has not, within the period of required residency, claimed residency in another state;

(5) shows by all attending circumstances that his intent is to make Alaska his permanent residence.

The purpose and object of this Act is stated as (AS 38.40.010):

> ...the development of its natural resources to seek and accomplish the development of its human resources by providing maximum employment opportunities for its residents in conjunction with natural resource management (§1 ch 191 SLA 1972).

Although this writer has some doubts concerning the constitutionality of the Alaska statute, it must be assumed valid. Cf. NAACP v. F.P.C., -U.S.- (1976). However, potential practical ramifications of the policy allegedly furthered by the statute should be noted. First, limitations on hiring create an artifical restriction on labor availability and probably result in a less-competent work force. The increased cost which could flow from reduced efficiency is absorbed by the rate base. Second, since out-of-state hiring is restrained, prospective workers may feel impelled to go to Alaska and establish residences there. Thus, increased inmigration may result. In sum, even assuming that the presumed state interest protected by the statute constitutionally justifies its discrimination against other U. S. citizens, the practical effects of the hiring policy could be deleterious to both the pipeline and Alaska.

VIII

DELIVERY WITHIN THE LOWER 48 STATES-- DISPLACEMENT CONSIDERATIONS

Three major proposals for delivering Alaskan natural gas to lower 48 markets have been advanced, and each relies to some extent on displacement mechanisms. Delivery by displacement is a procedure long used in the industry and sanctioned by the Commission. Although the Commission has disclaimed authority to order pipelines to interconnect 1/, traditionally pipelines have voluntarily entered into such arrangements to take advantage of the savings gained by not physically moving gas to distant markets when closer supplies could be exchanged and utilized. Added to the equation are two new considerations: first, as reserves of gas in the lower 48 states have fallen, there has been a large increase in excess capacity of existing pipelines which can be used to move displaced gas; second, there is an increased appreciation of the energy component cost of construction of new facilities.

El Paso Alaska's entire delivery system within the contiguous states is dependent upon various displacement arrangements essentially involving most of the major natural gas pipelines in the U.S. 2/ Under El Paso Alaska's proposal, natural gas delivered by it to California would displace that gas now coming to California from the San Juan, Panhandle-Anadarko and Permian Basin fields. Displaced gas would be delivered to midwest pipelines in the Anadarko area, and a new line would be built from the Permian area to the Texas Gulf Coast to effect delivery of displaced gas to eastern pipelines. Arctic Gas has proposed an essentially direct delivery scheme, with delivery to midwest and eastern pipelines over an eastern delivery leg constructed by Northern Border and extended, as initially proposed, to Delmont, Pennsylvania, and with deliveries to western companies over a western leg developed essentially by expanding the existing systems of PGT and PG&E. Alcan's method, similar to that of Arctic Gas, would rely on the proposed Northern Border facilities for delivery to midwest and eastern markets and on the Northwest Pipeline and PGT systems for delivery to western markets.

1/ The Manufacturers Light and Heat Co., 39 FPC 294 (1968).

2/ The certificate applications necessary to effectuate any such displacement proposal have not yet been filed with the Commission.

Respecting Arctic Gas, the Commission Staff made two counter-proposals: (1) that Northern Border terminate its proposed facilities at Kankakee, Illinois, and make deliveries to easternmost pipelines by displacement; and (2) that the western leg not be constructed, with deliveries to all western markets made by displacement. Northern Border has modified its application to adopt almost completely Staff's proposal for ending its pipeline at a point near Chicago. The Arctic Gas western-leg proposal is still in controversy and is discussed in detail below.

No challenge has been made to the technical feasibility of El Paso Alaska's displacement proposal, although New York refers to undescribed and vague uncertainties in its Position Brief (p.2). Consultants for Arctic Gas have studied the feasibility of lower-48 delivery by displacement of project volumes delivered in California, and while that study reflects a delivery plan which is somewhat different from El Paso Alaska's in technical detail, cost, and fuel requirements, it confirms the viability of the general concept. A description of the El Paso Alaska proposal is set forth below. 1/

A. <u>The "Western Leg" Issue</u>

As a part of their overall project, the Arctic Gas companies have proposed the construction of "western-leg" facilities from Alberta to California and "eastern-leg" facilities from Alberta to Illinois to transport directly to market the volumes of Alaskan gas which may be purchased by western and eastern

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1/ CPUC raises the specter that western shippers would lose their entitlements to El Paso's lower-48 suppliers if there were an outage in Alaskan deliveries. The fear is that eastern and midwestern shippers would not relinquish the displacement volumes to which they had become accustomed (Position Br. 15). This fear is unfounded. As CPUC well knows, the fields and transmission facilities are controlled by El Paso, and El Paso would have to honor its contracts with western shippers. Eastern and midwestern shippers' gas would have suffered outage in Alaska. The reversal of flow in the El Paso line and restoration of lower-48 volumes to western shippers would not constitute abandonment of service to the other shippers.

shippers. 1/ This assurance of equal access for both the east and the west to initial and probable future supplies of gas from Alaska's North Slope and other promising areas in the far north is described by its sponsors as one of the chief benefits offered to the nation by the Arctic Gas project.

The Commission Staff opposes the authorization of western-leg facilities primarily on the grounds that delivery of Alaskan gas to west-coast markets could be accomplished more economically by combining (a) use of capacity on the existing Alberta-California pipeline system which will become partially idle as a result of anticipated future curtailments of exported Canadian gas, and (b) transportation of western entitlements of Alaskan gas to the midwest over the eastern leg of the Arctic Gas Project while displacing to the west equivalent volumes of gas from traditional southwest producing areas which are now delivered to the midwest.

Following the conclusion of the evidentiary hearing on this issue, briefs or statements of position in support of western-leg facilities were filed by the Arctic Gas group, California Public Utilities Commission, the California Gas Distributors (Pacific Gas and Electric Company, Southern California Gas Company, and San Diego Gas & Electric Company), and (jointly) Northwest Pipeline Corporation and Alcan Pipeline Company. Opposing briefs or statements were filed by Staff and Conservation Intervenors. New York State Public Service Commission filed a statement calling for the burden of any increased costs or savings foregone to be borne by western consumers, if western-leg facilities are approved absent express findings that such facilities are presently needed to transport contract volumes of Alaskan gas to west-coast markets.

Unlike its earlier position taken at the hearing that the question of the western leg was shrouded in doubt and that a decision should be deferred, Staff now takes the position that

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1/ Arctic Gas had originally proposed that its eastern-leg facilities extend to Delmont, Pennsylvania, thus affording direct delivery to each of the six Northern Border Pipeline companies. Acceding to a Commission Staff recommendation, it now proposes to terminate Northern Border's facilities near Dwight, Illinois; make direct deliveries to Northern Natural Gas Company, Michigan-Wisconsin Pipe Line Company, and Natural Gas Pipeline Company of America; and make deliveries by displacement to Panhandle Eastern Pipe Line Company, Texas Eastern Gas Transmission Corp., and Columbia Gas Transmission Corp.

the net savings from nonconstruction displayed on the record, are so substantial to U.S. consumers as a whole that the western-leg should be specifically denied. The collective position of the western-leg advocates ranges from an attack on Staff's basic projection of limited future Canadian exports to a political blast that California should not be relegated to second-class citizenship by being made dependent on exchange displacement agreements with midwest and eastern pipelines. 1/

1. Proposed Project

The western leg of the Arctic Gas project comprises those facilities, transactions and requested authorizations proposed by certain members of the Arctic Gas group for the purpose of directly delivering a portion of the Alaskan gas to markets west of the Rocky Mountains.

As now proposed, Alaskan gas purchased by shippers Northwest Alaska Company (Northwest Alaska), Pacific Interstate Transmission Company (Pacific Interstate), and Natural Gas Corporation of California (NGC) for resale in the Pacific Northwest and California to their respective affiliates--Northwest Pipeline Corporation (Northwest Pipeline), Southern California Gas Company, and Pacific Gas and Electric Company (PG&E)--would be transported over the facilities of Canadian Arctic Gas Pipeline Limited (CAGPL), Alberta Natural Gas Company Ltd (ANG), Pacific Gas Transmission Company (PGT) and PG&E. 2/

The current western-leg proposal is designed to deliver initial volumes of 659,000 Mcfd. 3/ These volumes represent roughly 30% of the total initial Alaskan gas flow on the CAGPL

1/ Unfortunately, it is necessary to address the tactics of the California protagonists. They have at times made it difficult to view the western-leg proposal solely on the weight of the evidence, interjecting overtones of regional discrimination into the proceeding. The decision here is not dependent in any way on these emotional arguments, which are not supported by facts.

2/ Although the Northwest companies formally withdrew participation in the Arctic Gas Project when they determined to sponsor the competing Alcan Project, they have stated their support for the Arctic Gas Project with a western leg if that project is the one approved.

3/ Since the filing of initial applications in 1974 and while the hearings were in progress, the western-leg proposal has undergone continuing modification and refinement reflecting a variety of different routes, designs and ownership alternatives. The present proposal, basically looping existing lines, is described in the Reply Brief of Arctic Gas dated October 7, 1976.

system (2.25 Bcfd) and reflect the now-defunct prior advance payment agreements between the western-leg shippers (or their affiliates) and Exxon Corporation, Atlantic Richfield Company and Standard Oil Company of California for Prudhoe Bay gas reserves. The gas would be delivered from Caroline, Alberta, to the U.S.-Canadian border near Kingsgate, British Columbia, over facilities of CAGPL and ANG. From Kingsgate, the major portion of the gas would be transported by PGT to Malin, Oregon, and then by PG&E to Antioch, California. PGT would deliver 22,000 Mcfd for Northwest Alaska to the facilities of Northwest Pipeline at Stanfield, Oregon, or other delivery points in Oregon, Washington, and Idaho. At Antioch, PG&E would take into its general system supply 200,000 Mcfd shipped by NGC; the remaining 437,000 Mcfd owned by Pacific Interstate would be delivered by PG&E to the system of Southern California Gas Company either directly at existing points of interconnection between the two systems or by exchange. Such exchange could be facilitated by the substantial LNG volumes expected to be delivered to Southern California Gas Company by the Pacific Alaska (Docket No. CP75-140) and Pacific Indonesia (Docket No. CP74-160) projects pending before the Commission.

In order to accomplish delivery of the expected western-leg volumes, CAGPL proposes to construct 177 miles of 30-inch pipeline from Caroline, Alberta, to the Alberta-British Columbia border (Brief dated 6/11/76), together with 13,500 hp of compression; ANG proposes a complete looping of its existing system between the Alberta-B.C. border and Kingsgate with 36-inch pipeline, but no added compression is necessary for the expected initial volumes; PGT would install 591.9 miles of 36-inch pipeline from Kingsgate to Malin, Oregon, thus completing the looping of its entire 612-mile, 911-psig, existing system, 1/ without the need for additional compression to accommodate the initial volumes; and PG&E would install, without added compression, 281.6 miles of 36-inch pipeline from the Oregon-California border to Antioch, California, and an additional 8 miles of 36-inch line from Antioch to its Brentwood terminal to accommodate receipt of Prudhoe Bay gas into the PG&E system. 2/

1/ The existing PGT system has a capacity of about 1 million Mcfd and transports Alberta gas to various points throughout the Pacific Northwest and to California.

2/ If no gas supplies are available from other sources to permit delivery of Pacific Interstate volumes by exchange, PG&E would construct an additional 120 miles of 36-inch pipeline on its system to make direct delivery of such volumes to Southern California.

The CAGPL and ANG applications are presently pending before the National Energy Board of Canada, and the proposed facilities of PG&E will require application to and approval by the California Public Utilities Commission. 1/ The export, import, and sales applications do not necessarily depend on approval of a western leg; they could be amended, if necessary, to conform to an approved displacement scheme.

2. The Staff Alternative

The Staff displacement proposal is bottomed primarily on its evaluation that substantial curtailments of exports of Canadian gas by Canadian authorities will result in the permanent idling of the major portion of the existing capacity on the PGT system. Based upon the Canadian National Energy Board (NEB) Supply and Requirements Report of April 1975, Staff perceives a 1981 shortfall of nearly 60% in exports under outstanding NEB licenses. Assuming a *pro rata* reduction in exports, PGT would have idle capacity of 601,000 Mcfd by 1981 (111/17,753).

On this premise, styled Case I, Staff recommended that available PGT capacity be utilized to transport directly the bulk of Alaskan gas destined for west-coast markets, with the balance of 36,000 Mcfd to be delivered by displacement. However, if Canadian curtailments are not as severe as Staff predicts, Staff presented a Case II showing that up to 433,000 Mcfd could be displaced to western markets through the Northern Border facilities, leaving 204,000 Mcfd for direct delivery over idled PGT capacity (111/17,756). 2/ Staff argues that a transmission/displacement scheme in either Case I or II must inevitably result in lower costs to consumers than construction of a western leg.

1/ The applications consolidated herein with respect to the present western-leg proposal are: PGT-Docket No. CP74-241 (looping of its transmission facilities), Docket No. CP74-242 (Presidential permit for border facilities), Docket No. CP75-252 (import of NGC's Alaskan gas from Canada); NGC - Docket No. CP75-247 (export of gas from Alaska); Pacific Interstate--Docket No. CP75-248 (export and import of Alaskan Gas) No. CP75-249 (sale to Southern California Gas Company); and Northwest Alaska--Docket No. CP75-250 (export and import of Alaskan gas), Docket No. CP75-251 (sale to Northwest Pipeline). Applications of Interstate Transmission Associates Arctic (ITAA) in Docket Nos. CP74-292 and 293, and Northwest Pipeline in Docket No. CP76-174 are mooted by the present proposal.

2/ The Staff study was based on assumed western entitlements of 637,000 Mcfd, apparently not including the assumed 22,000 Mcfd for Northwest Alaska, *supra*. The difference in volume is unimportant for present purposes.

The responsive presentation of Arctic Gas conceded the technical feasibility of the Staff's displacement proposal; it also admitted that elimination of the western-leg facilities, based upon the design then being considered, would result in a net reduction in project capital costs of $512 million and a reduction in average annual project transportation cost of service of roughly $50 million. 1/ Staff accepts these computations of net savings. These figures represent (1) elimination of about $770 million in western-leg facilities (197/33,460); (2) authorization of a fully powered 42-inch line on the eastern leg south of Empress, Alberta; (3) deliveries to the eastern leg at the 2.25-Bcfd level; and (4) full displacement of the western-market requirements for 20 years over the Northern Border facilities. The study also showed that about the same annual savings could be achieved if a 48-inch line, rather than a fully powered 42-inch line were authorized south of Empress, 2/ although the capital cost saving would be reduced to about $366 million.

Staff argues that the Arctic Gas displacement study is a "worst-case" analysis, and thus the $50 million annual cost-of-service savings should be viewed as a minimum. This is said to be so because the study assumes full displacement delivery of western-market Alaskan gas for 20 years, i.e., no available capacity on PGT's existing facilities, presuming that Canadian authorities will not curtail exports to western U.S. markets under outstanding export licenses and, moreover, will "evergreen" or extend outstanding licenses as their termination dates fall due commencing in the 1980's (197/33,380-2, 33,414-5).

3. Discussion

Aside from the claims made by the California distributors and CPUC that denial of a western leg somehow would relegate western consumers to "second-class citizen" status in their attempts to secure a fair share of present and prospective Alaskan supplies, and apart from any considerations which may be mandated

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1/ With the latest western-leg design hereinabove described, the savings in capital costs and annual cost of service would be reduced (Arctic Gas Reply Brief dated 10/7/76, pp. 6-7).

2/ The higher annual fixed charges resulting from use of the larger line would be offset by reduced fuel requirements (197/33,402).

by the Alaska Natural Gas Transportation Act of 1976, 1/ there are cogent reasons for rejecting the displacement scheme urged by Staff.

The Staff proposal is keyed to very substantial and permanent reductions in Canadian deliveries to PGT, commencing either prior to or coevally with the expiration of the applicable export licenses. Absent such action by Canadian authorities, long-term displacement of full western entitlements over a fully loaded 42-inch eastern leg would not result in a true saving to the nation's consumers. The $50 million "saving" relied upon by Staff would be achieved at the expense of additional fuel requirements amounting to some 70 billion Btu per day, 2/ thus resulting in significantly lower volumes of natural gas available to the nation's markets (197/33,483). Compared with Staff's estimated one-time energy requirement of 48 trillion Btu to construct the western leg (205/33,384), a net energy loss would be experienced in less than 2 years. Over the 20-year life of the project, the cost of replacing the net energy loss would more than wipe out the suggested $50 million annual saving in transportation cost, since the replacement energy in California market would mainly take the form of high-cost electricity. 3/ And while it may be accurate to claim that assumption of full displacement of western entitlements for 20 years constitutes a "worst-case" basis for measuring the savings in transportation costs resulting from displacement, it does not necessarily follow that $50 million is the minimum measure of such savings. The magnitude of any such savings on a full-displacement basis would be a function of the final design of the facilities, which is not yet known.

Even if there were true overall savings resulting from the displacement proposal, such savings would have to be apportioned among the specific eastern and western markets to be served. While the question received considerable attention on the record, no satisfactory resolution was suggested. Staff's illustrative

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1/ Staff, Arctic Gas, Alcan, and El Paso have filed supplemental briefs solely on the question of whether the 1976 Act requires the construction of a western leg if Arctic Gas is authorized. The arguments raised are immaterial in light of the disposition of the issue reached herein.

2/ About 70,000 Mcfd at 1,000 Btu/cu.ft. equivalent.

3/ Even with the lower incremental fuel requirements of 38.8 billion Btu per day associated with the selection of a 48-inch eastern leg, the cost of replacing the net energy loss over the project life could be expected to erase the savings in transportation costs (205/35,072-3).

allocations of the alleged savings demonstrated by the incremental cost studies cannot necessarily be taken as the measure of how such savings should or will be reflected in transportation charges, since Staff would leave determination of such charges to negotiation of the parties. Accordingly, it is not possible on this record to assess the effect on delivered cost to specific markets of any savings which might flow from the Staff displacement proposal.

The magnitude of this problem has been understated by Staff. The displacement arrangement suggested by Staff is not dependent solely upon negotiations between pipeline companies presently having gas to swap or excess capacity. If a western leg were not certificated, substantial volumes of gas would have to move to Dwight. It would be necessary, therefore, either to maximize the capacity of Northern Border's existing 42-inch diameter pipeline or to build a larger diameter Northern Border pipeline. Substantial capital costs are attendant to any such plan, and the western-leg purchasers would have to pay for the expansion. But if Staff is correct that the PGT excess capacity will grow, Northern Border capacity installed now to permit displacement could quickly become excess to Northern Border's needs. Absolving western-leg customers of these costs would result in higher costs to eastern-leg customers. Additionally, since Northern Border must be designed and financed now, there is no opportunity merely to defer a decision on the western leg and wait for the entire project to be otherwise completed.

The entire panoply of this problem is dismissed by Staff as being something which pipelines "work out all the time." None of the Arctic Gas sponsors are so sanguine, pointing out that negotiations to finance new facilities on someone else's line, which could be miscalculated, are not the same as negotiations for excess capacity on an existing pipeline or a swap of gas between two pipelines having a mutual and identical interest.

The west-coast supporters of the western leg in fact did offer to pay more for the privelege of betting that they are right and Staff is not, but even if one were to require such payments, the formula for determining such "cost" defies rational resolution. There is no way on this record to compare the cost of cheap and easy expansibility to the eastern-leg customers if the western-leg is built as against the delays and unknown costs in unknown future years if it is found necessary to fully load Northern Border's 42-inch line now and deny cheap expansibility in the future. Nor can one determine the allocation of the cost of the alternative energy required by the decrease in energy delivered to the west coast under the displacement plans--i.e., the extra cost of electricity borne by the California consumers because of the gas they did not receive. This, however, would be a legitimate concern of the California consumers, just as increased energy deliveries in the east would have to be weighted against decreased charges to the west. Just sorting out the considerations, much less assigning dollar values to each, may be beyond the talents of mere mortals. Given the large sums of money which might be associated with such considerations, Staff's belief that agreement would be reached easily is entitled to little weight.

Moreover, the substantial long-term reduction in Canadian deliveries anticipated by Staff, which constitutes the linchpin of its proposal, is the reflection of Staff's appraisal of the future action of Canadian authorities on the basis of the NEB Report of April 1975. That report, based upon information of 1974 and perhaps earlier vintage, did not consider the impact of new frontier gas supplies in assessing Canada's supply and demand position in future years. A considerably more favorable appraisal of Canada's ability to continue exports at present levels is reflected in An Energy Strategy for Canada, issued under the authority of the Minister of Energy, Mines and Resources in early 1976. This later report does consider the effect of frontier supplies; it strongly suggests that after 1982, with the advent of gas supplies from the frontier areas (including Mackenzie Delta) under an energy price structure adjusted to current levels of international oil prices, the Canadian supply will substantially exceed demand (including exports) for a number of years (PG-126, pp. 80, 84). In other words, any curtailments which might occur in the late 1970's or early 1980's should prove to be temporary.

Needless to say, the Arctic Gas Project would materially assist in marketing Canadian frontier gas at an early date and thus mitigate the prospect of an overall shortfall in Canadian supplies. Moreover, as the Strategy report points out, Canada's increasing dependence on foreign oil, which is creating severe balance of payments deficits for energy, could be mitigated by "increased flows of foreign exchange into Canada, arising from trade in other energy commodities and from higher natural gas prices" (p. 114). This point was also made by the members of the California Public Utilities Commission. The Canadian authorities have already taken steps to increase flows of foreign exchange by substantially increasing export prices for natural gas; the motivation to maintain these balance of payments benefits will undoubtedly remain high.

While circumstances impinging upon the decisionmaking process of the Canadian government in the energy field will change over time, and while that government quite properly will continue to reappraise both its energy goals and the means it perceives to be best suited to meeting those goals, the present outlook for Canadian gas exports at current levels after 1982 appears optimistic.

Accordingly, authorization of a western leg for the Arctic Gas Project if certificated, is required by the present and future public convenience and necessity. The displacement alternative espoused by Staff, predicated as it is upon what presently appears to be an unduly pessimistic view respecting Canadian curtailments and justified on the basis of transportation cost savings which may be largely illusory, cannot be considered a preferable alternative on this record.

The specific design recommended by Staff moreover would produce a system operating at or near full capacity from the outset, leaving no room for cheap expansion to take advantage of future supply from the developing Alaskan region (197/33, 397). 1/ In contrast, the eastern- and western-delivery legs now proposed by Arctic Gas, while reflecting substantial reductions and modifications from the designs originally proposed in order to improve the economy and efficiency of gas delivery, nevertheless provide capability for transportation of Alaskan volumes above the 2.25-Bcfd level solely by increasing compression, and thus contain a reasonable measure of the cheap expansibility customarily deemed desirable in attaching new transmission facilities to new, promising supply areas.

Despite the conclusion reached herein, it must be acknowledged that the presentation by Staff witnesses James M. Kiely, Jr. and David C. Lathom has accomplished a truly valuable service in the public interest by providing and prompting an extensive and enlightening record on the general issue of delivery by displacement and by encouraging the Arctic Gas sponsors to improve the designs of both the proposed eastern and western legs with substantial reduction in capital costs and annual costs to gas consumers.

This initial conclusion on the western-leg issue is, of course, subject to further review and refinement by the Commission based upon the filing and certification of actual gas purchase

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1/ Staff witness Lathom conceded that the advent of significant additional gas volumes from the northern regions within a reasonable time would call for construction of a western leg (108/17,238; 110/17,462; 197/33,460).

contracts, approval of financing arrangements, evidence relating to receipt of other necessary regulatory approvals, and any other factors significantly affecting the size or design of the system. The lead times involved in these projects are very large. Under the schedules contemplated by the 1976 Act, final action by Congress on the Presidential decision is expected no earlier than late 1977. The second-stage proceeding before this Commission is not likely to commence before early 1978. Prior receipt of all necessary authorizations, including any additional legislation which may be necessary to protect the financial viability of the chosen project, will mean construction would not commence earlier than late 1978 or early 1979. Everyone must recognize that significant changes in circumstances can occur by that time which may dictate adjustments in the sizing or design of any portion of the approved transportation system.

One further point. Staff argues that since the proposed PGT facilities are unnecessary, their environmental impact, however minimal, is unacceptable, and therefore PGT fails on environmental grounds. The short answer is that the facilities are herein found to be necessary; the record discloses, and Staff concedes, that in such circumstances, western-leg facilities are environmentally acceptable, subject to appropriate conditions. It is found that if Arctic Gas is certificated, then construction of the western leg is in the public interest and is required by the public convenience and necessity.

B. El Paso Alaska's Lower-48 Delivery Presentation

1. The Proposal

El Paso Alaska's basic blueprint for delivery of Alaskan gas volumes in the lower 48 states is summarized in Exhibit EP-265. This study constitutes a refinement of earlier evidence illustrating the feasibility of moving Alaskan gas, directly and by displacement from the west-coast regasification plant, throughout the lower 48 states by using existing pipeline systems.

In brief, the plan calls for western markets to receive through existing and new facilities in California the bulk of the Alaskan gas, in volumes equivalent to the sum of their own Alaskan entitlements, their shares of El Paso Natural's Alaskan entitlements, and their shares of El Paso Natural's and Transwestern's existing supply in the Permian Basin, Panhandle and San Juan areas. The balance of the Alaskan gas would be moved eastward to the California-Arizona border through existing and new facilities in California. Flow would be reversed in El Paso Natural's and Transwestern's existing facilities east of

California, and those facilities, with minor modifications and reinforcement, would carry the remaining Alaskan gas eastward to the Panhandle-Anadarko and Permian Basin areas. El Paso Natural would also construct a new 42-inch pipeline from the Permian Basin to Refugio on the Texas Gulf Coast. Delivery of volumes equivalent to their Alaskan entitlements would be made to midwestern and eastern shippers from the easterly flow of Alaskan gas, as substantially augmented by gas volumes from existing domestic supply areas of Transwestern and El Paso Natural, which presently serve western markets. Deliveries to illustrative midwestern shippers would be accomplished through direct interconnections in the Panhandle-Anadarko area; eastern shippers would receive their gas through the new line to the Texas Gulf Coast, all but one by direct interconnection. The midwestern and eastern shippers would then move the gas to market over their existing systems, with relatively minor modification and reinforcement.

For purposes of designing the "Lower 48" transportation facilities, El Paso Alaska has assumed design conditions of maximum production from the regasification plant, coupled with a minimum expected daily flow from El Paso Natural's and Transwestern's producing fields east of California. The study also assumes the proposed abandonment in Docket No. CP75-362 of one of El Paso Natural's 30-inch lines on its southern system from west Texas to California so that it can be converted and utilized by Sohio for eastward transportation of Alaskan crude oil. 1/

The study presents two cases: peak-day availability of Alaskan gas at the tailgate of the west-coast regasification plant at a 2.4-Bcfd level and a 3.1-Bcfd level. Unless otherwise indicated, the discussion herein refers to the 2.4-Bcfd case. Additionally, the study sets forth several different approaches to the problems of fuel allocation and the allocation of system cost-of-service.

The study assumes an allocation of Prudhoe Bay gas reserves on the basis of shippers' purchase entitlements set forth in the Prudhoe Bay advance payment agreements, since in El Paso Alaska's view no better basis is presently available for estimating final apportionment, despite the fact that such agreements have either

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1/ El Paso Natural has undertaken to seek abandonment of a second 30-inch line on the southern system upon Sohio's request, if sufficient traffic of Alaskan crude develops in the future.

been cancelled or are being renegotiated. 1/ The assumed allocation reflects an approximately equal distribution of Alaskan gas reserves among western, midwestern, and eastern shippers as follows: western--34% (PG&E, Southern California Gas, Northwest Pipeline and El Paso Natural); midwestern--34% (Panhandle, Natural Gas Pipeline, Northern Natural and Michigan Wisconsin); eastern--32% (Columbia Gulf, Texas Eastern, Tennessee and Transco). The existing systems of these twelve companies constitute an interconnected grid of pipelines which can deliver Alaskan gas, directly or by displacement, to the major market areas of the United States.

2. Facilities and Fuel

a. Western LNG

Within the State of California, Western LNG Terminal Company would provide all LNG and gas handling and transportation under contract to El Paso Alaska. In addition to new facilities which it proposes to construct and operate, Western LNG has undertaken to arrange for the use of existing facilities of PG&E and of Southern California Gas or its affiliates. The new facilities will consist of a 247-mile, 42-inch pipeline (looped at its western end with a second 42-inch line) at an estimated cost of $305 million. Since the plant discharge at the Western LNG regasification terminal proposed at Point Conception will provide pressure up to 1,440 psig, no added compression would be necessary on facilities within California in order to move gas to the markets of PG&E, Southern California Gas and Northwest Pipeline and to the California-Arizona border.

b. El Paso Natural and Transwestern

Transwestern purchases about 80% of its gas supply in the Permian Basin and the balance in the Panhandle. About 75% of its gas now moves west to California markets, and the remainder is delivered to Cities Service Gas Company in the Panhandle. El Paso Natural obtains 62% of its supply in the Permian Basin, 8% from the Panhandle-Anadarko, and 30% from the San Juan Basin.

1/ The advance payment agreements covered all but 17.9% of the field reserves, including Alaska's royalty gas. For purpose of the study, El Paso Alaska assumed that this 17.9% would be acquired by Tennessee Gas Transmission, Transco, El Paso Natural and Northwest Pipeline. Subsequently, on November 12, 1976, the State of Alaska announced that it had agreed to sell shares of its 12.5% royalty gas to Tenneco Alaskan Inc., an affiliate of Tennessee Gas Pipeline (50%), El Paso Natural (25%), and Southern Natural (25%).

About 80% of El Paso's sales are now made to California utilities at the Arizona border, with the balance sold in West Texas, New Mexico and Arizona. El Paso Natural estimates that by 1982 the average-day supply from its presently dedicated sources will have declined to about 1,889 MMcfd, but that daily flow of about 372 MMcfd from newly contracted sources will result in 1982 supply of about 2,260 MMcfd. 1/ Transwestern estimates that supply from presently dedicated sources will have declined to about 319 MMcfd by 1982, but that new supply may approximate 135 MMcfd, for an indicated total of about 454 MMcfd in that year. 2/ El Paso Natural has a current westward throughput capability of about 4,000 MMcfd, and Transwestern's is about 750 MMcfd. 3/

The proposal calls for the flow in the existing systems of El Paso Natural and Transwestern to be reversed to permit transportation of Alaskan gas from the California-Arizona boundary some 800 miles to the Panhandle-Anadarko and Permian Basin producing areas of Texas. El Paso Natural would construct a new 42-inch line from Permian Basin to Refugio on the Texas Gulf Coast, a distance of 432 miles. Delivery of Alaskan entitlements, by displacement from Transwestern's and El Paso Natural's present supply sources and by easterly flow from California, would be made by direct interconnection to the midwest shippers--Panhandle Eastern, Michigan Wisconsin, Natural Gas Pipeline and Northern Natural--in the Panhandle-Anadarko area and to three of the four eastern shippers--Texas Eastern, Transco and Tennessee--on the Texas Gulf Coast. Delivery would be made on the Texas Gulf Coast to other pipelines for Columbia's account. 4/

1/ Exhibit EP-114.

2/ El Paso Alaska actually projected a somewhat higher new supply for Transwestern of 208 MMcfd, based upon annual new reserve additions of 139 Bcf. Transwestern's own estimate of annual new reserve additions is 90 Bcf, which would indicate new supply of about 135 MMcfd.

3/ As noted above, El Paso Natural seeks to abandon one of its 30-inch lines.

4/ The proposed design would permit the flow in the existing El Paso Natural and Transwestern systems to be restored to a westerly direction if necessary to offset the effects of an unexpected interruption of Alaskan gas to the west coast (58/8891).

The estimated cost by 1982 of new facilities for Transwestern, essentially addition of compression horsepower, is $6.5 million. El Paso Natural's additional cost of facilities by 1982 is estimated at about $290 million, consisting essentially of additional compression horsepower and partial looping on its Plains-to-Dumas, Texas, line and the new 42-inch line to Refugio. Construction over the 3 years subsequent to that initially required for 1982 service would total about $3 million for Transwestern and El Paso.

It is proposed that El Paso Natural and Transwestern would each contract with El Paso Alaska to provide the eastward transportation and delivery service. 1/

c. Other Major Facilities

With the allocation of Alaskan gas reserves and the direct delivery and displacement arrangement herein described, about 32% of the volumes would be delivered by Western LNG in California, 35% would be delivered to midwest pipelines in the Panhandle area by El Paso Natural (24%) and Transwestern (8%), 31% would be delivered to eastern pipelines by El Paso Natural in the Texas Gulf Coast area, and 1% would be delivered by El Paso Natural to its east-of-California customers.

In testing the capability of existing midwestern and eastern pipeline systems to handle their Alaskan gas, it was necessary for El Paso Alaska to estimate the supply that each could reasonably expect by 1982 from traditional and other sources. This was done essentially by extending each company's own 5-year projection for each supply region and adding an estimate of new flowing supply based upon the company's share of reserve additions in the supply regions. Reserve additions for each supply region presently supplying these pipelines were adopted from the Commission's Natural Gas Survey Volume I, Chapter 9, Case II. These Case II estimates, reflecting average additions of 12.2 Tcf per year for the period 1975 through 1983, are considered to represent the upper limit of reasonable expectations, in that additions in these areas have averaged only 7.2 Tcf for the past 6 years.

Based upon evidence presented by witnesses for the prospective shippers, El Paso Alaska estimates that total additional facilities costing about $33.5 million will be required on the systems of

1/ While Transwestern has not yet stated whether it is agreeable to the use of its system in the general manner proposed by El Paso Alaska (159/26,163), it is unlikely that it would impede such arrangements.

Natural Gas Pipeline, Tennessee, Transco, Michigan Wisconsin and Panhandle. All of these companies are parties, and none suggested that El Paso's estimates were out-of-line.

d. Fuel

The lower-48 delivery plan proposed by El Paso Alaska would increase fuel requirements in those pipeline systems with increased physical flow and decrease requirements in systems utilized to transport gas by displacement. All midwestern and eastern shippers would expend additional fuel to move the Alaskan gas to their markets. Since gas flows would be partially or completely displaced in the systems of west-coast shippers and in the El Paso Natural and Transwestern systems, these systems would consume substantially less fuel than they would otherwise require. 1/ These fuel decrements would constitute additional gas available without incremental cost to the western companies. On a 1982 average-day basis, the incremental fuel utilized from regasification terminal to market, expressed as a percentage of Alaskan entitlement received at the terminal, is estimated by El Paso Alaska to be about 6% overall for midwestern shippers and 7% overall for eastern shippers. Western shippers, however, would show a fuel savings of more than 4%. On a total-system basis, the net incremental fuel use is estimated at 2.8%.

Other than California's concern, discussed *supra*, there is no question that El Paso can design operational displacement systems. Unlike the situation with Arctic Gas, the displacement proposal here is not dependent in any measure on shortfalls of Canadian deliveries. Facilities costs and transportation costs could be forecast, and each party would have full knowledge of both its short- and long-term commitments and obligations.

A large number of unknowns, however, could work to make its proposal more efficient over the long term, such as additional discoveries of natural gas in the Permian Basin or Hugoton-Anadarko, or less efficient, such as either a shortfall of projected discoveries in these same fields or an increased throughput of Alaskan gas requiring greater physical transportation of gas east with a greater fuel consumption. In sum, the El Paso proposal is clearly feasible.

1/ Under the proposed delivery scheme, the net delivery of Alaskan gas eastward across the California-Arizona border on a 1982-1983 design-day basis is only 83.5 MMcf for the 2.4-Bcfd case. (For the 3.1-Bcfd case, it would be 561 MMcf.) Such net delivery will increase over the years to compensate midwestern and eastern shippers for the diminishing displacement volumes resulting from the projected production decline of gas supplies attached to the El Paso Natural and Transwestern systems.

COST ALLOCATION

These applicants propose differing methods of allocating the costs of service among shippers. In the ensuing discussion, primary attention will be devoted to the generic allocation of costs between U.S. shippers and Canadian shippers on jointly used (Canadian) delivery systems. Since cost allocation on U.S. pipeline systems will remain directly subject to the jurisdiction of the Commission after selection of a particular route and there is nothing inherently objectionable about any of the proposals, there is no need at this juncture to conduct an in-depth study of the cost allocation methods proposed for use on those systems.

Briefs specifically addressed to the question of cost allocation were filed by Arctic Gas, El Paso, Alcan and Staff. The matter was also addressed by various parties in other briefs, particularly tariff, Canadian law, position and wrap-up briefs.

A. El Paso

The method by which El Paso proposes to allocate transmission costs among shippers is set forth in Section 5 of the General Terms and Conditions of El Paso's pro forma FPC Gas Tariff, Original Volume No. 1, on Original Sheet Nos. 123-126 (Exhibit No. EP-276). Therein the El Paso delivery system is broken into its seven segments, referred to as "cost components." 1/ Anticipating deliveries within Alaska, El Paso has utilized the Mcf/mile method for allocating the costs of pipeline transmission through Alaska (cost component 1). Under this method, each shipper absorbs a percentage of the total cost of service of this portion of the system. That percentage is determined by multiplying the shipper's daily delivery quantity times the distance over which that quantity is carried and dividing that product by the product of the total daily volume of gas transported for all shippers times the total distance covered. Since all shippers within the lower 48 states will share the benefit of the Alaska liquefaction and marine facilities, the cryogenic tanker fleet, and the California marine, storage, and regasification facilities (cost components 2 through 4), the cost of service for these items will be allocated on a volumetric basis. The remaining cost components

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1/ The cost components are individually identified in subsections 1.8 through 1.14 of Section 1 of the tariff's General Terms and Conditions.

involve transmission within California (cost component 5) and, utilizing displacement (see the section of this decision concerning, inter alia, displacement, infra), between California and the Permian Basin (cost component 6) and between the Permian Basin and the Hugoton-Anadarko Basin or Texas Gulf Coast areas (cost component 7). The cost of service for these sequential components will be allocated in accordance with the so-called "zone gate" method, which charges each shipper a unit delivery rate based on the costs incurred to the point of delivery; the shipper is charged none of the costs for transmission beyond that point. No party has objected to the method of cost allocation proposed by El Paso, and it is found appropriate.

Of more than academic interest is a suggestion offered by Stone and Webster Management Consultants, Inc. in connection with a study which it performed under the auspices of El Paso (Exhibit No. EP-265). Stone and Webster begin by observing that most of the costs incurred by either the El Paso or Arctic Gas projects will result from bringing gas to the lower 48 states. Stone and Webster then reason that, since selection of an Alaskan gas transportation system will turn on the "larger United States' public interest," it is wise to consider an alternative method of cost allocation which would neutralize the fortuitous advantage provided certain lower-48 customers simply because they happen to be closer to the port of entry than other customers. The result would be a uniform lower-48 national transmission rate for Alaskan gas, which Stone and Webster have calculated for both the 2.4-Bcf/d and 3.1-Bcf/d cases (EP-265).

Although the national-rate concept does not constitute an affirmative proposal of any of the applicants and has not been pursued on brief by any of the parties, it nevertheless may afford an imaginative and appealing rate-making option to the Commission. All of the applicants take the position that financing any project will require various assurance or guarantees from lower-48 consumers that capital costs will be recovered in all events, and only El Paso contends that additional government financial assurances will not be necessary. 1/ Where such collective assurances from either consumers or taxpayers, or both, may be forthcoming, the national-rate concept makes sense and should be seriously considered during the next evidentiary phase of this proceeding.

1/ Treasury, as discussed more fully in the Financing section, relies on the sufficient perfection or rate-tracking mechanisms to obviate federal financial support (Brief 12).

B. Arctic Gas

The basic cost allocation method of the Arctic Gas project is the Mcf/mile method described in connection with El Paso's cost component 1 allocation. It is incorporated into the various *pro forma* tariffs submitted to this Commission by Alaskan Arctic (Item by Reference AA-P(i)), Northern Border (Item by Reference NB-N), and Pacific Gas Transmission (Exhibit No. PG-86) and to the Canadian NEB by Canadian Arctic (Exhibit No. AA-6). In the case of Alaskan Arctic, since all U.S. shippers are currently expected to transport gas from the same location (Prudhoe Bay) to the same delivery point (Alaska-Yukon border), the method, in reality, becomes a purely volumetric allocation based on entitlement.

The Mcf/mile method of allocation is well-suited to the initial construction costs and initial shippers for Canadian Arctic and Northern Border, and no party takes exception to its application on this basis. However, in its brief on cost allocation, El Paso raises the question of how subsequent additions to Canadian Arctic's plant between the Mackenzie Delta and Empress, Alberta, 1/ will be cost-allocated, i.e., whether such additional costs 2/ should be rolled in or assigned incrementally to the beneficiaries (U.S. or Canadian, depending on the source of gas which necessitates the particular plant expansion) to preserve the lower cost-of-service by the original plant for existing, or traditional, shippers. The simple answer to the question is that, under Canadian Arctic's *pro forma* tariff, the additional costs would be rolled in under the Mcf/mile method, which, once approved, could not be modified without authorization from the NEB. Flow-through of any increased (or decreased) unit costs to U.S. shippers would require approval by this Commission (FPC). The ultimate concern, however, is not that any specific method of allocating additional costs be adopted but instead that the method which is eventually adopted be applied in an even-handed manner between U.S. and Canadian interests. As discussed in the Canadian Law section, there is no reason to believe that the NEB would not treat fairly

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1/ That portion of the Arctic Gas project currently scheduled to provide joint transmission service to U.S. and Canadian shippers.

2/ It appears that higher overall unit cost will generally result only in the event of additions to physical plant capacity by looping, regardless of whether the new gas is Canadian or Alaskan. Where only additional compression is needed, the economies of scale should operate in such a manner as to reduce overall unit costs.

all users of common facilities. In any event, the ad referendum treaty contemplates such equitable treatment and in all likelihood would be in place before a joint facility were built. 1/

For the western delivery portions of the Artic Gas project (Alberta Natural and PGT) which are expansions of existing transmission systems providing service to U.S. markets, the Mcf/mile method will incorporate the cost of identifiable new facilities and a portion of the costs of existing facilities (on a volumetric basis) used to transport Alaskan volumes. No party opposes this aspect of Arctic Gas' allocation plan.

C. Alcan

Throughout the last series of briefs, and particularly in the Allocation Rebuttal Brief, Alcan engages in an ad hominem response to what it asserts are ad hominem arguments made by other parties--specifically Arctic Gas. The gravamen of its position is that accusations of improper motives for sponsoring the Alcan application are untrue and do a disservice to the Alcan's Canadian sponsors' desire to serve the United States shippers (Allocation Rebuttal Brief 2). It then states:

> Alcan offers no apologies for the proposed modifications in its project. From the outset, Alcan's sponsors have seriously considered the criticisms of the shippers, the Commission Staff, the Presiding Judge, and the competing applicants, and it has proposed changes where these criticisms were deemed to have merit. Alcan will continue to approach its project with this attitude. Given the uncertainties which are inherent in any major construction project in the arctic regions of North America, flexibility is most assuredly an asset, not a weakness (footnote omitted).

Admittedly, the hearing process before a regulatory agency is a crucible in which applications are often transformed to reflect the dialogue on the record. Alcan's initial proposal, however,

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1/ The ad referendum treaty presently provides that governmental authorities having jurisdiction over a "Transit Pipeline" such as the Canadian Arctic system must apply all regulations, requirements, terms, and conditions which affect that pipeline "equally to all persons and in the same manner" (Article IV Paragraph 2).

was so defective in so many areas that the continuing process of revision has resulted in an inability on the part of the other parties or the Presiding Judge to know at any given time, or predict for any future time, what Alcan is or will be seeking.

The conclusion is inescapable that an application not capable of being analyzed has been filed. The proof adduced is only to that filing and cannot be made applicable under any circumstances to the modifications and amendments made by Alcan in its Rebuttal Brief. That findings required to be made by the Commission are impossible is admitted by Alcan page 19 of Alcan's Allocation Rebuttal Brief, where it states:

> Rather than engage in a point by point refutation of the contentions of Arctic Gas and El Paso, it will suffice to state that AGTL Canada, upon reflection, has decided to propose that its cost of service for the transportation of Alaskan gas be calculated on a rolled-in basis, rather an incremental basis. Filings being made with the National Energy Board demonstrate that the rolled-in method will result in a lesser cost of service for U.S. shippers during the initial years of operation.
>
> For purposes of cost of service comparison, Alcan recognizes that the Presiding Judge and the Commission must rely upon AGTL Canada's cost of service evidence in this record which was calculated under the incremental method. If Alcan is certificated, AGTL Canada will present evidence in Phase II of the hearings to show the cost of service savings which will result during the initial years from using the rolled-in method.

Arctic Gas, as that applicant bearing almost the entire brunt of the Alcan attack, has an understandable reason to question the <u>bona fides</u> of Alcan's Canadian sponsors.

Despite AGTL's chucking the theory and costs presented at the hearing on allocation, it still applies to Westcoast, and it is necessary to review what AGTL originally asked the American consumer to accept as "fair." Cost allocation methods <u>per se</u> present no real problem to those Alcan sponsors whose facilities will provide service solely to U.S. shippers. 1/ Alcan and Foothills would be carrying gas through Alaska and the Yukon, respectively, in completely new systems, the cost of which would be allocated among U.S. shippers on a volumetric entitlement basis. Northwest, which would transport gas from a point of interconnection with Westcoast on the U.S.-Canadian border near Sumas, Washington, to a point of interconnection with the facilities of PGT near Kent, Oregon, would be constructing about 350 miles of new pipeline to transport Alaskan gas for other U.S. shippers as well as itself. Its method of cost allocation consists first of assigning these incremental facilities an appropriate portion of the costs of Northwest's overall system, with which they would be integrated, and then allocating that amount between off-system shippers and on-system customers on a volumetric basis. Shippers and customers alike would pay a fixed charge rate under the Northwest tariffs. 2/

With Westcoast and AGTL Canada, by contrast, the allocation issue becomes most significant. For allocation purposes, Westcoast has divided its transportation system into four sections labeled parts A-D in both the Westcoast tariff (FPL-107) and the illustration in Appendix A of the Alcan sponsors' Allocation Brief. 3/ Part A will be constructed by Westcoast to carry gas from a point of interconnection with Foothills at the Yukon-British Columbia border to Fort Nelson, B.C. Until such time, if any, as Canadian gas is introduced into the system above Fort Nelson, all of the construction and operating costs attributable to that portion will be allocated incrementally to U.S. shippers under Section 9.A of the Westcoast tariff. Part B will be constructed between Fort

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1/ Ancillary features of these sponsors' <u>pro forma</u> tariffs are subjected to criticism, however--primarily by Arctic Gas.

2/ Northwest's proposed allocation provisions are contained in Sections 3.1(a) and (b) of Original Sheets 10 (Revised), 10a and 10b of Northwest's Pro Forma FPC Gas Tariff, Original Volume No. 3 (Item by Reference NW-P).

3/ This discussion presupposes that the Westcoast route will in fact be used for the transmission of Alaskan gas, a presumption which is not altogether certain according to the testimony of Westcoast's witness Phillips (241/42,165-169). Arctic Gas doubts whether lower-48 shippers would voluntarily choose transportation over the relatively high-cost Westcoast system.

Nelson and a point of interconnection with AGTL on the British Columbia-Alberta border near Zama. The facilities will also be totally costed against U.S. shippers of Alaska gas but will be subject to a credit for the costs of any Canadian gas flowing into the Westcoast system through these facilities, either directly or through displacement, as provided in Section 9.B of the Westcoast tariff. Parts C and D of the Westcoast system connect Fort Nelson with the Northwest system at the British Columbia-Washington border near Sumas, Washington. This section of pipeline spans some 865 miles and is currently in place, although up to 403 miles of this pipeline will, it appears, ultimately be looped in connection with the transportation of Alaska gas. The cost of the looped, or "new" facilities, will be costed incrementally to U.S. shippers under Sections 9.C and 9.D of the Westcoast tariff; the cost of existing, jointly used facilities will be allocated between Canadian and U.S. users on a rolled-in basis thereunder.

AGTL Canada intends to construct a short connection between the British Columbia-Alberta border and Zama for transportation of the Alaskan gas which it receives from Westcoast. 1/ Further, AGTL Canada will construct looping and compression facilities on portions of the transmission system of its parent, AGTL, to be used solely for the transmission of Alaskan gas. Finally, AGTL Canada will lease capacity in those portions of the AGTL system which are not specifically looped to transport Alaskan gas. Capacity in these unlooped portions of the AGTL system will be shared with Canadian gas. AGTL Canada's method of cost allocation on its own, newly constructed facilities is set forth in Section 9 of its *pro forma* Canadian tariff (Exhibit No. FPC-108) and essentially duplicates the Westcoast formula. The AGTL Canada tariff also provides for recovery of those costs allocated to AGTL Canada by AGTL under the terms of the Alcan Lease Agreement between them (FPL-109).

In allocating between U.S. and Canadian shippers the costs of facilities which will transport Alaskan and Canadian gas volumes in a common stream, it is the Alcan sponsors' stated objective (Brief, p. 3) to insure that U.S. shippers pay *all* costs attributable to the transportation of Alaskan gas, and *only* those costs. The Alcan sponsors have codified their intent in Section 4.4 of

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1/ About 1.7 Bcf/d, or two-thirds of the 2.4 Bcf/d currently contemplated by the Alcan sponsors. The remaining one-third (700 MMcf/d) will have been diverted south by Westcoast for transmission to Northwest.

their revised Definitive Agreement (Item by Reference AP-W, p. 17). On its face, this document provides that transportation charges for Alaskan gas will be based on the "full incremental costs of service for all new facilities required to transport Alaska gas" and "full incremental costs of service for all additions to existing facilities required to transport Alaska gas," plus volumetrically allocated costs of service for existing facilities or additions thereto to be utilized to carry both Alaskan and Canadian gas. Existing surplus capacity is thereunder made available to shippers of Alaskan gas "until such time as that capacity is required for the transmission of Canadian gas," at which time "other capacity will be provided" by the Canadian system for transmission of Alaskan gas. The clear impact of this language is that all of the presently existing Westcoast and AGTL plant is reserved for Canadian gas (241/42,210). Moreover, when additional facilities have to be constructed for the transportation of Canadian gas, they will be charged on a rolled-in, rather than incremental, basis (209/36,146).

The Alcan sponsors' asserted justification for this overt Canadian bias 1/ is their belief that new sources of Canadian gas (initially from the Mackenzie Delta via the Maple Leaf project) will be shipped for the benefit of current customers who have heretofore paid for the existing system. (See the statement of Westcoast's witness Phillips at 241/42,157.) Ironically, it seems that a significant share of these "current customers" are in fact located within the lower 48 states. 2/ When there is added to this the possible elimination of Canadian natural gas exports to the U.S. as export permits expire, it becomes apparent that, as a practical matter, the allocation methods of these Alcan sponsors would provide Canadian shippers with the use of a relatively low-cost line which has been financed to a significant extent by

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1/ Staff in its Allocation Brief suggests that the Canadian bias built into the Definitive Agreement will be exacerbated as a practical matter by the sequence of events currently envisioned, whereunder U.S. shippers will assume the incremental costs of initial looping; later, when further system expansion is needed to accomodate Canadian volumes in excess of the present 1.4-Bcf/d capacity of the Westcoast system, it will be accomplished at a relatively lower cost than that of the initial looping, to the overall benefit of the Canadians.

2/ Fifty-eight percent of the volume presently transported by Westcoast is delivered to Northwest.

revenues received from U.S. shippers, while these shippers and, derivatively, their U.S. customers, are asked to absorb the higher costs attendant to construction and operation of new facilities. 1/

During the hearing a question arose as to whether this preferential treatment for Canadian gas would apply to other than existing facilities, i.e., whether, once the existing 1.4-Bcf/d capacity on the Westcoast system is wholly utilized for the transportation of Canadian volumes, the excess Canadian volumes would be permitted to displace Alaskan volumes and to provide Canadian customers with the benefits of partially depreciated loop facilities. Testimony presented by E. C. Phillips at 150-A/24,629E-629J left the clear impression that the Alcan sponsors intended to employ a so-called "evergreening incremental" policy of cost allocation under which Alaskan gas would be continuously and incrementally charged with the cost of the newest, most expensive, undepreciated facilities, even when those facilities were required to develop new sources of Canadian gas. This impression was later refuted by tariff witnesses Willms and Smith at 208/35,859-864. At 208/35,859-860, witness Smith advised that once construction to move the total volume of Alaskan gas is completed, the Alaskan gas rate base will not increase again unless additional Alaskan volumes are introduced into the system. Thus, under this gloss, once Westcoast has constructed looping facilities to accomodate 700 MMcf/d of Alaskan gas (30 percent of the total Alaskan volume of 2.4 Bcf/d), no further "ouster" will occur. Witness Phillips accepted this interpretation of Section 4.4 of the Definitive Agreement on later cross-examination (241/42,195). Nevertheless, Section 4.4 of the Definitive Agreement remains unchanged, and the possibility of another policy reversal on this point by the Alcan sponsors' management persists.

The Canadian bias characteristic of the policy-making of the Alcan sponsors takes on special and comfortless significance when it is realized that the determination which governs a particular allocation between U.S. and Canadian gas is made solely on the basis of the future engineering design and management decisions

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1/ An argument by Alcan that the costs of additions to existing systems will be substantially less than the cost of an entirely new (all-U.S.) system, given the available right-of-way, compressor stations, staff, housing, access roads and landing strips (241/42,215-216), would be a non-sequitur. The issue here is not absolute cost but the manner in which these costs are to be allocated, and if the distribution is unfair, it is not significant that Alcan argued that the dollar values are lower.

of Westcoast and AGTL. Consider the case of AGTL, a company which currently exists primarily to carry Alberta-produced gas to points on the provincial border for further transport. With the onset of Alaskan and Mackenzie Delta gas, AGTL will be called upon to expand its system in various respects. Since all financing for all facilities required for AGTL Canada will be undertaken by AGTL, 1/ the decision of which new facilities will be owned by AGTL Canada and which by AGTL will be made solely by AGTL management. The cost allocation of shared facilities is likewise subject to speculation. The AGTL system presently consists of 22 segments for cost allocation purposes. Different segments have different imbedded costs, and very little of AGTL's throughput uses all segments. The record contains no breakdown of the AGTL system to indicate which of the existing facilities will be shared by U.S. and Canadian shippers. Nor are the terms of the Alcan Lease Agreement (FPL-109) of any help in this regard. The U.S. public is asked to accept on faith the Alcan sponsors' assurances that AGTL's cost allocations will be performed in an equitable manner. An aggrieved shipper is not without legal recourse in the event of a questionable allocation, of course. But, in view of the number of regulatory authorities potentially involved 2/ and the delay inherent in proceedings before these bodies, it is found that a tariff such as Canadian Arctic's, which clearly and equitably establishes the method by which costs are to be allocated and thus minimizes the likelihood of dispute between the company and the shipper, is greatly preferable to tariffs such as those proposed by Westcoast and AGTL Canada.

1/ Of relevance here is the fact that AGTL Canada's rates will reflect the capital structure of its parent, AGTL. AGTL's equity ratio has been thickened by depreciation and now stands at roughly 60/40. AGTL Canada's equity might be further thickened, for example, by increasing retained earnings (but see Section 9.4 of the AGTL Canada Rate Schedule, FPL-108, ostensibly fixing $500,000 as the ceiling for such increase unless AGTL Canada's ability to meet its financial obligations will be impaired thereby) or by accelerating debt retirement payments to its parent in lieu of paying dividends. As equity ratios increase, so do rates--in this case, rates to U.S. customers. This same concern for corporate integration applies to Foothills (Yukon), which will be wholly controlled at the outset by Westcoast and AGTL.

2/ In the case of AGTL Canada, such authorities include the Alberta Public Utilities Board, the NEB, and, with respect to flow-through of costs by U.S. shippers, the FPC.

The cost allocation provisions contained in the pro forma Westcoast and AGTL Canada tariffs, colored as they are by the Definitive Agreement, are totally unacceptable to U.S. consumers. No project embodying such provisions or capable of so operating can be approved. The Alcan sponsors' witness Blair indicated at 240/41,871-873 that the Alcan sponsors might be willing to amend the Definitive Agreement to provide for "a single (rolled-in) rate and equal treatment for all gas regardless of nationality," but, to date, no such amendment has been presented on the record.

This entire discussion takes on added significance since Westcoast's costs exceed the comparable incremental costs of AGTL facilities carrying all of Alcan's volume. It is astounding that a proposal would be made to apportion U.S. gas volume solely to alleviate alleged Canadian pipeline company transmission imbalances and then to heap on top of it an unfair cost allocation procedure. One can only speculate why Northwest, with its obviously perceptive management, permitted itself to be saddled with a patently unacceptable cost allocation proposal.

The next issue which must be addressed is the 30/70 split between Westcoast and AGTL Canada. The Alcan sponsors have designed their system to transport 2.4 Bcfd of Alaskan to Fort Nelson, British Columbia. There the stream will be divided and a volume of 700 MMcfd (or about 30 percent) will be sent south through the Westcoast system to Northwest at the British Columbia-Washington border at Sumas. The remaining 1.7 Bcfd will travel eastward to the British Columbia-Alberta border, where it will be picked up by the AGTL Canada system for transit to Zama Lake and then south for delivery in part to Alberta Natural Gas Company for transportation to Kingsgate and in part to Foothills (Saskatchewan) for delivery at Monchy. 1/

The rationale governing the Alcan sponsors' decision to divide the Alaskan volumes at Fort Nelson on a 30/70 ratio has never been satisfactorily explained. While the subject was persistently explored through questioning by Arctic Gas' counsel, on August 31, 1976, a summary of the testimony of Foothills' witness Ronald M. Rutherford, speaking on behalf on the Alcan sponsors, shows how little was learned:

1/ The ratio is set forth in Section 3.1(c) of the so-called "Definitive Agreement" (Item AP-W).

(1) An admission that, according to Exhibit AP-12, the unit transportation cost of Alaskan gas to Kingsgate (via AGTL (Canada) will be 9 cents less than the unit transportation cost of Alaskan gas to Sumas (via Westcoast) in 1983, 14 cents less in 1987 (208/35,760-761);

(2) An attempted qualification that these differentials are valid only where the 30/70 split is presumed, the argument being that the 30/70 split maximizes available capacity on both the Westcoast and AGTL systems and any modification of that split would result in inefficiency and higher unit cost (208/35,761-764); 1/

(3) An admission that the Alcan sponsors had made no study of the actual cost impact of shipping Westcoast's share, or a portion thereof, through the AGTL line to Kingsgate and from there through PGT's system to Kent, Oregon, the point of intersection between Northwest and PGT (208/35,765);

(4) Statements indicating the 30/70 split reflected the Alcan sponsors' best estimate of the ultimate division of Alaskan gas volumes between the western and eastern lower 48 states (208/35,766-768) and that the additional western volumes to be delivered through Kingsgate using spare capacity of AGTL and Alberta Natural were added only after Northwest made tentative arrangement to acquire the State of Alaska's royalty gas (Id.); witness Rutherford did not view as significant the fact that the west-east split effectively become 39/61 as the result of this development (208/35,768-769);

(5) Concern that the whole Alcan project could not be organized and financed without Westcoast's participation, thus mooting the question of whether the Alcan sponsors would accept a western delivery route which minimized reliance on, or altogether bypassed, the Westcoast system below Fort Nelson (208/35,770);

1/ Absent flow charts which Alcan was either unwilling or unable to provide, no finding can be made regarding the relative degrees of available capacity on the system of Westcoast or AGTL.

(6) Reassurance that, to the extent there is a difference in price between the gas flowing through the Westcoast system and the gas entering via AGTL and Alberta Natural at Kingsgate, Alcan would attempt to prorate that differential among the western shippers and thereby equalize cost responsibility (241/35,770-771); this apparently means that all shippers would pay higher costs, since they would all have to bear a part of Westcoast's higher costs.

Speaking for AGTL Canada, witness Robert L. Pierce stated that he saw no difficulty in modifying the 30/70 split to transport all of PG&E's and SoCal's volumes through the AGTL system (208/35,749). Westcoast's witness Smith began by stating that Westcoast would also be amenable to such a change (208/35,750). On further thought, witness Smith took and maintained the position that the Alcan project was designed on the basis of the 30/70 split and that, until modified as a matter of policy, that arrangement would govern (208/35,751-752; 35,757). AGTL Canada's witness Pierce construed witness Smith's remarks not as an absolute unwillingness to negotiate a split on other than the 30/70 basis, but instead as a refusal to answer the question in deference to the Alcan sponsors' policy witnesses (208/35,756). Witness Pierce gave a similar response when asked whether AGTL Canada would be willing to install additional facilities to accommodate more than 70 percent of the Alaskan volumes (208/35,756-757).

Accordingly, these questions were later put to Alcan's policy witness and President, E. C. Phillips, who testified in effect that the 30/70 split was originally selected as a model upon which to structure the engineering and financing aspects of the Alcan project. Mr. Phillips advised that the 30/70 split was never intended to be sacrosanct and that, indeed, the Alcan sponsors would be willing to revise that assessment to suit the collective will of the western U.S. shippers. He added that no determination of the economics of any such change had been made, e.g., 40/60 or 80/20 (241/42,165-168).

Clearly, the Alcan sponsors have failed to show that the 30/70 split will result in unit costs to western U.S. consumers lower than any other transportation arrangement utilizing the facilities of these sponsors. Indeed, there is reason to believe that the 30/70 split was adopted, in the first instance, to secure a Westcoast participation in the Alcan project by assuring that the Westcoast line below Fort Nelson would be allocated a suffient volume of gas to fill existing excess capacity, thereby warranting construction of additional loop facilities which would inure to the ultimate benefit of Canadian customers. (See extended discussion, supra.) To their credit, some to the Alcan sponsors have indicated that the 30/70 split is not etched in stone. Unfortunately, however, the record does not permit determination of the optimal ratio, i.e., that which would provide sufficient service to the western U.S. at the lowest cost.

It is found that Alcan has failed to show on this record that a project including Westcoast on an arbitrary basis meets the public convenience and necessity and that costs associated with using Westcoast, given the arbitrary nature of its inclusion and the higher cost of transportation which were to be borne by the U.S. consumer, is consistent with the public interest. An Alcan project, if approved, should not include Westcoast on any of the bases shown on this record.

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MARKETABILITY

This section deals with marketability solely in terms of the methodology usually employed by the Commission in conventional cases, wherein a determination of the need for additional gas supplies is made and then the projected delivered cost of the gas in question is compared with the cost of alternative energy supplies to test whether the gas can be sold.

None of the parties, including the applicants, have specifically addressed on brief the issue of marketability of Prudhoe Bay gas in these terms, although some of the parties have directly or obliquely questioned whether the Alaska gas is in fact marketable or should be marketed on the terms proposed by the applicants. Thus, for example, the Staff questions the reliability of the record evidence on marketability, primarily on the grounds that, in the absence of sales contracts, the specific markets have not been yet been identified and that the market studies of record may be unrepresentative of the actual situation by the time any of the proposed projects can be built (Position Br. 35). New York PSC claims the record is as yet insufficient to permit a sufficiently reliable estimate of the likely delivered cost of Alaskan gas and accordingly questions whether any of the proposed systems are in the public interest (Position Statement, 1; Comments on Financial and Tariff Brief, 5). California PUC also cites the lack of a reliable estimate of delivered cost, pointing principally to the lack of evidence on wellhead price, gathering and conditioning costs, and distribution costs (Position Br. 6). 1/

The only detailed conventional study of marketability of Prudhoe Bay gas in anticipated lower-48 markets was presented by Arctic Gas witness Schantz, and that study provides the basis for the discussion in this section. The Schantz study, however, is predicated, inter alia, on 1975 dollar costs for (1) natural gas field price (assumed alternatively, for both lower - 48 and Alaskan production, at 55¢ per MMBtu and $1.00 per MMBtu), (2) alternative fuels (e.g., oil at $12 per barrel), and (3) project (Arctic Gas) transportation costs.

On the basis of the assumptions made, the Schantz study supports the marketability of Prudhoe Bay gas on either a rolled-in or incremental basis. Other assumptions, discussed in the Economic and Finance sections, infra, question some of Schantz's assumptions.

1/ Alcan also points out the dearth of record evidence on these costs (Init. Economics Br. 59-64).

A. <u>The Need for Additional Natural Gas Supplies</u>

No elaborate demonstration is needed to show the existence of the nationwide natural gas shortage which first began to appear in the late 1960's. The reserve-life index for the lower 48 states (ratio of proved reserves to annual net production) has fallen from roughly 30 years in the mid-1940's to about 20 in 1960 (34 FPC at 319) and now stands at about 10 (Ex. AA-111). This resulted from the combination of expanded use and dwindling supplies; in each year since 1968, new natural gas reserve additions in the lower 48 states have failed to keep pace with net production by a substantial margin. In recent years, moreover, that failure has been most pronounced where supplies in the interstate market must be purchased in areas where there is intrastate competition (Ex. AA-111). 1/ The shortage has been judicially recognized in numerous proceedings. See, *e.g.*, Opinion No. 699, 51 FPC 2212, 2217, n. 10.

The major interstate pipeline companies are now unable to meet their annual firm market requirements and will probably continue curtailments indefinitely. The Commission has projected a 22% shortfall, affecting more than 40 states, in interstate pipeline deliveries to meet firm requirements for the 1976-1977 winter heating season (FPC Release No. 22608, September 9, 1976).

The nine interstate pipeline companies comprising the Arctic Gas group have projected that their composite total gas supplies from all sources (including imported gas, synthetic gas, and Alaskan gas when available) will fall short of total annual requirements by 21% in 1975, 28% in 1980 and 26% in 1985 (Ex. AA-111). In 1975, these companies marketed about one-third of the total natural gas production in the lower 48 states and over one-half of the lower 48 production marketed by all interstate pipelines. Under present projections, they will be unable to satisfy fully their requirements in the categories of highest priority during the early 1980's.

B. <u>Specific Market Areas for Alaskan Gas</u>

Neither the location of the markets to be served by Alaskan gas (either directly or through displacement), the allocation of Alaskan gas volumes among such markets, nor indeed the total

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1/ There can be no question that the relatively poorer recent performance of the interstate pipelines to secure new natural gas supplies is attributable in large measure to the fact that producer field prices for interstate sales have been limited by federal regulation to levels substantially below the intrastate market prices which have remained unregulated.

volumes of Alaskan gas to be marketed (and the date of first availability) can be explicitly determined prior to (1) execution and publication of definitive gas sales contracts between the producers (including the State of Alaska for its royalty gas) and the successful bidders for the purchase of the gas and (2) publication of a final Prudhoe Bay Field unitization and operating agreement approved by the State of Alaska, upon which the terms of such sales contracts in part depend.

Nevertheless, the record supports the reasonable conclusion for present purposes that total marketable volumes of Prudhoe Bay gas will be available within the range of 2.0 to 2.5 Bcfd, commencing in 1982 or 1983. Further, the parties apparently share the belief that, in general, the identity of the shippers is more or less independent of the particular transportation project to be certificated. El Paso and Alcan both explicity accepted the composition of the Arctic Gas group as the basic for all discussions of marketing. Thus, the evidence of Dr. Radford L. Schantz of Foster Associates, Inc., which focuses on the marketability of Alaskan gas in the regional markets served by the nine interstate pipelines comprising the Arctic Gas group, provides an appropriate general indicator of the marketability of Alaskan gas in the lower 48 states. 1/ The markets of these pipelines include states in the southwest and Pacific coast areas, the midcontinent area, and the northern tier running from the Dakotas and Nebraska in the west to the Atlantic coast from New England to Virginia --in all, a substantial majority of the lower 48 states. (See e.g. Ex. NB-2; 35/5206-5207, 5216-5217.) Their principal market states are California, Ohio, Michigan, Illinois, Minnesota, New York and Pennsylvania (AA-111).

C. Factors Affecting Marketability of Alaskan Gas

Numerous factors can affect, in varying degrees, the demand for and thus the marketability of Alaskan gas. Chief among these are the availability and price of natural gas produced in the lower 48 states (and contiguous offshore areas), imported LNG and Canadian pipeline supplies, and synthetic gases derived from

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1/ The presentation of FEA Deputy Assistant Administrators John K. Freeman, William W. Hogan, Jr., and Bruce A. Pasternack affords valuable insights into the factors affecting the demand for Alaskan gas and the major impact of uncertainty in estimating such demand (158/25,988-26,032; Ex. ST-40); see also Ex. EP-231, Alaskan Natural Gas Transportation Systems, A Report to the Congress Pursuant to Public Law 93-153, United States Department of the Interior.

coal and petroleum products; the regulatory environment; 1/ and price competition with other energy forms, principally electricity and fuel oil.

1. Gas Supply in 1985

The projection of future natural gas production in the lower 48 states is a matter of considerable controversy, depending upon a host of assumptions and a variety of scenarios that can be constructed by informed analysts on the basis of those assumptions (158/25,990-6; 174/28,652). Ex. AA-111 sets forth the results of six recent industry and government production forecasts for the year 1985, involving a dozen scenarios ranging from a low of 13.8 Tcf to a high of 24.1 Tcf. The average of the six forecasts is 16.0 Tcf. Dr. Schantz recommends this intermediate figure as the estimated 1985 lower-48 production level. 2/ Such level can be expected to decline sometime after 1985 (174/28,653; 158/26,019).

Achieving 16 Tcf from lower-48 production in 1985 will require annual new reserve additions of about 13.5 Tcf in the intervening period, an amount some 44% greater than the average yearly additions of 9.4 Tcf from 1968 to 1975; the necessary level of reserve additions will not be realized without increased price incentives, either in the form of new gas price deregulation or higher regulated prices (174/28,653, 28,660). 3/ Based upon current market share, the Arctic Gas pipelines should be able to secure 5.2 Tcf of lower-48 production in 1985 (174/28,653).

1/ The regulatory environment includes pricing policy--such as deregulation of new domestic interstate natural gas supplies, the use of uniform nationwide price ceilings, or the continuation of the present regulatory scheme with unregulated intrastate sales and regulated interstate sales; outer continental shelf leasing policy; the level of government controls and incentives affecting availability of supplemental gas supplies such as synthetic gases and imported LNG; and restrictions on certain end uses of natural gas.

2/ Sixteen Tcf is the average of the following forecasts: Shell Oil Co.--14.5 Tcf; Gas Requirements Committee--14.7 Tcf; Exxon Corp.--15.3 Tcf; FPC Bureau of Natural Gas--15.4 Tcf (average of two cases); Department of the Interior--17.0 Tcf; FEA--19.1 Tcf (average of 6 cases).

3/ The substantial bulk of the new reserve additions will be nonassociated gas responsive to gas prices; the much lesser portion represented by associated gas will be responsive mainly to oil prices (Ex. ST-40; 158/25,997).

In addition to the lower-48 natural gas production, it is estimated that the 1985 supply for the Arctic Gas pipelines will include about 0.8 Tcf of LNG and synthetic gases and 0.5 Tcf of Canadian pipeline supply (Ex. AA-11; 174/28,662). These estimates reflect LNG and synthetic gas supplies, for which applications have already been filed with the Commission, and delivery of Canadian gas in accordance with the present terms of outstanding export licenses (174/28,664, 28,681). Finally, 1985 supply to those pipelines from the Arctic Gas project itself is estimated at 0.8 Tcf, a level within the range of 2.0 Bcfd to 2.5 Bcfd.

Thus, total 1985 gas supply for the Arctic Gas pipeline group has been estimated by Dr. Schantz at 7.3 Tcf.

2. The Character of the Market to be Served

The pipeline group had total market requirements of 8.7 Tcf in 1975, of which 3.9 Tcf fell in FPC priority 1 (residential and small commercial), 1.9 Tcf fell in priority 2 (large commercial; firm industrial requirements for plant protection, feedstock and process needs; and pipeline customer storage injection requirements), and 2.9 Tcf were classified in priorities 3 through 9 (various industrial requirements not included in priority 2). 1/ Total requirements are projected to increase by 1.3% per year to 9.9 Tcf in 1985. With supplies of 6.9 Tcf in 1975, curtailments extended into priorities 3 through 9. However, with requirements in priorities 1 and 2 increasing to 7.6 Tcf in 1985, estimated available supply of only 7.3 Tcf in that year indicates projected curtailments into priority 2 (Ex. AA-111; 174/28,654). Hence, absent both Alaskan gas and other gas supplies, 1985 requirements in priorities 1 and 2 in the lower 48 states cannot be met.

3. Alternative Energy Forms

Inasmuch as Alaskan gas supplies would be used to meet requirements in priorities 1 and 2, they will enter the market in competition with other energy forms serving these requirements. Gas is the dominant energy consumed in residential and commercial markets 2/ in six of the seven key states served by the Arctic Gas pipeline group; only in New York is gas second to fuel oil. In each of the key states, electricity plays a strong competitive role, especially in California, where fuel oil consumption is negligible. Thus, gas and electricity compete for priority 1 and 2 markets in California; gas, fuel oil and electricity compete in the remaining six states (174/28,655; Ex. AA-111).

1/ See 18 C.F.R. 2.78.

2/ The commercial sector is considered representative of most industrial energy consumers in priority 2.

In recent years, electricity has been particularly successful in its growing penetration of the new-house heating market, increasing its market share on a nationwide basis from 20% in 1966 to 49% in 1974, with the acceleration of this trend corresponding generally to periods of gas supply insufficiency. Over this same period, fuel oil's share of the same market has generally declined. It should be noted that price is but one of the more important competitive factors affecting competitive energy forms in high-priority markets. Nonprice factors include the cost of installing, operating and maintaining the necessary facilities; clean burning qualities; heat control capability; versatility and convenience. Both gas and electricity command a nonprice premium over fuel oil (174/28,656).

4. Prices of Competitive Energy

In his analysis to test the effect of price on the marketability of Alaskan gas, Dr. Schantz compared competitive energy prices at the city gate of eight key metropolitan areas representing the larger markets served by the Arctic Gas pipelines. Prices are shown on both a "rolled-in" and an incremental basis in 1975 dollars per MMBtu. Dr. Schantz makes no attempt to forecast the general price of fuel oil, electricity and gas to the year 1985 and characterizes such projections as highly speculative (174/28,656, 28,675-6). 1/

Set forth below, in cents per MMBtu, are the results of Dr. Schantz's rolled-in price comparison. The rolled-in basis demonstrates, in his opinion, the "real world" situation of competitive energy forms, since the price of all gas streams is, in fact, rolled in at the city gate by the distributor, the price of "old" and "new" domestic is typically rolled in with foreign oil, and the price of electricity from all generating plants is rolled in by electric utilities. The comparison employs alternative field price levels for "new" U.S. supplies--55 cents per MMBtu for Alaskan gas and an equivalent 57 cents per MMBtu for "new" lower-48 gas (based on the then-current FPC national rate for "new" gas)--and alternatively employs an assumed field price of 100 cents per MMBtu. To these field prices are added the estimated cost of transportation to the city gate of each metropolitan area. The resulting city-gate prices are rolled in, by reference to 1985 volumes, with "old" lower-48 supplies, LNG, Canadian and synthetic supplies.

1/ However, since Alaskan gas, LNG and synthetic gas projects are not expected to be onstream until various dates after 1975, he utilized for these projects the forecast city gate cost (expressed in 1975 dollars) as of 1985.

Market Area	Gas Field Price at 55¢	Gas Field Price at 100¢	Distillate Fuel Oil	Residual Fuel Oil	Electricity
Minneapolis	94	119	205	202	393
Peoria	135	156	207	216	522
Chicago	98	121	205	209	520
Detroit	136	156	202	199	586
Columbus	124	149	207	206	533
New York City	110	135	207	218	923
San Francisco	187	194	192	207	595
Los Angeles	176	188	192	207	516
Simple Avg.	133	152	202	208	574

Dr. Schantz concludes from these results that Alaskan gas, when rolled in with other gas supplies, is competitive and marketable. Its price is substantially lower than the price of fuel oil and electricity for all metropolitan areas except in California, where there is parity with fuel oil. However, fuel-oil consumption is negligible in the high-priority uses of California (174/28,658).

On an incremental basis, the price of Alaskan gas in the several metropolitan areas, compared with the incremental price of fuel oil and electricity, is as follows:

Market Area	Arctic Gas Field Price at 55¢	Arctic Gas Field Price at 100¢	Distillate Fuel Oil	Residual Fuel Oil	Electricity 1/
Minneapolis	184	229	254	248	472
Peoria	203	248	261	268	626
Chicago	197	242	261	261	624
Detroit	195	240	260	253	703
Columbus	209	254	265	260	640
New York City	215	260	254	229	1108
San Francisco	181	226	265	275	714
Los Angeles	185	230	265	275	619
Simple Avg.	196	241	261	259	689

1/ The study shows electricity on an average-price basis. The figures set forth above reflect an upward adjustment of 20% to an incremental price level (174/28,658).

These figures indicate that Alaskan gas would be priced below fuel oil and electricity on an incremental basis in each of the metropolitan areas except New York City, where gas prices would be equivalent to distillate fuel oil and above residual fuel oil. But the New York price difference would be more than offset by nonprice premiums in excess of 50 cents, which favor gas over fuel oil (174/28,659, 28,675).

The incremental price of fuel oil obviously does not set a limit on the marketability of Alaskan gas. Respecting new installations, nonprice premiums favoring natural gas over fuel oil must be taken into account; in the existing high-priority market, where all the Alaskan gas is needed, the cost of converting from gas- to oil-burning facilities constitutes an additional consideration before reaching any oil price ceiling (174/28,659; Ex. EP-231). Electricity's penetration of the home heating market, despite its apparent price disadvantage, demonstrates the importance of competitive factors other than simple commodity pricing in measuring value to the consumer.

On its face, the Schantz study confirms the marketability of Alaskan gas, on either a rolled-in or incremental basis, given the assumptions made by its sponsor.

XI

CANADIAN ISSUES

Many issues originally raised about Canadian law no longer divide the parties. 1/ There remains no substantial dispute among the parties as to the authority of either the federal or provincial governments of Canada to tax or regulate inter- and intra-provincial pipelines. (See e.g. El Paso Can. Reply Br. p. 2.) Just, reasonable and non-discriminatory provincial treatment for transit pipelines is provided under the Canadian constitution. Attached hereto is Appendix H , Part I of which discusses in detail the various Canadian constitutional questions raised and discussed by the parties.

Nor is there a dispute as to the authority of the Canadian National Energy Board (NEB) to regulate Canadian inter-provincial pipelines. The technical and legal methods by which the NEB acts and by which its decisions are reviewed are set out in Appendix H , Part II. While the parties dispute the expected timing of an NEB decision and the length of time review may take, the dispute now extant centers essentially on political issues--whether the NEB will act impartially, in a timely fashion for U.S. interests, and include U.S. and Canadian Mackenzie Delta gas in the same package.

The parties disagree about the meaning and impact of the recent ad referendum hydrocarbon treaty (Appendix H, Part III), but the applicants essentially agree that the result here will not end the negotiations with the Canadian Government (Arctic Gas Reply Br. 10; El Paso Reply Br. 3). This section deals only with those issues concerning the reliability and timing of routing U.S. gas through Canada.

It must be understood that it is with some trepidation that one embarks upon a discourse of what another sovereign state may or may not do. But, given the nature of the proceedings and the importance of the issues to the parties, fear of misunderstanding must give way to the need of the public to have the issues aired.

A. Export-Import Jurisdiction

Section 3 of the Natural Gas Act requires the Commission to grant import and export licenses for natural gas unless it finds that such proposed exportation or importation will not be consistent with the public interest. Executive Order No. 10485,

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1/ Briefs were filed by each applicant and Staff. Numerous other parties also took positions on these issues in their Position Briefs and Wrap-up Briefs.

issued September 3, 1953, delegated to the Commission authority to issue, upon appropriate findings, permits for the construction, operation, maintenance or connection of facilities at the borders of the United States for the exportation or importation of electric energy or natural gas, subject to favorable recommendations by the Secretary of State and Secretary of Defense. This authority is applicable to physical connections at borders. Following the procedures described by the Commission in Phillips Petroleum Company, et al., 37 F.P.C. 777 (1967), the Chairman of the Commission sought the advice and views of the Department of State and the Department of Defense so that the Commission might have their views before taking action on its decision. Both have responded not only through letters but also through witnesses and interrogatories which were put in the record. Because the hydrocarbon treaty between the U.S. and Canada has been initialed, although not yet ratified by the United States, the discussion must include consideration of its impact. The impact of the treaty will be discussed infra in this section, but its mere existence bespeaks a sub silentio statement on the part of the President that reasonable commercial activity with Canada for the movement of hydrocarbons is generally in the national interest.

It goes without saying that the Commission does not make foreign policy for the United States, and its mandate to determine whether imports or exports of natural gas are consistent with the public interest is not a delegation of authority to make foreign policy. The Supreme Court addressed a similar problem concerning the Court's intrusion into the foreign policy arena in Chicago & Southern Air Lines, Inc. v. Waterman Corporation, 333 U.S. 103 (1948), which involved judicial review of a certificate to engage in foreign commerce which is subject to approval by the President. The Court held (333 U.S. at 111):

> * * * But even if courts could require full disclosure, the very nature of executive decisions as to foreign policy is political, not judicial. Such decisions are wholly confided by our Constitution to the political departments of the government, Executive and Legislative. They are delicate, complex, and involve large elements of prophecy. They are and should be undertaken only by those directly responsible to the people whose welfare they advance or imperil. They are decisions of a kind for which the Judiciary has neither aptitude, facilities nor responsibility and which has long been held to belong in the domain of political power not subject to judicial intrusion or inquiry. [citation omitted] * * *

As there, the political consideration raised here touches on matters which are primarily the prerogative of the President, and the sparse legislative history of Section 3 does not indicate the extent to which the Congress intended the Commission to make such inquiry of its own. Factors similar to those which the Court found persuasive in its refusal to interfere with the President's determination of foreign policy considerations are present here. Any argument which requires, in final analysis, determinations of reliability of foreign governments with respect to their future political and economic action patently involves those elements of "prophecy" discussed by the Court which are best left to the President and others expressly delegated to make decisions in those spheres.

Under Section 5(d) of the 1976 Alaska Gas Act, the Commission is barred from basing its decision on whether Canada has acted upon an application to carry U.S. gas through Canada. An appreciation of how Canada might act and the timing of such action however, is still an important ingredient in weighing the merits of the applications at this time: no one would expect the U.S. to seriously consider a proposal which on its face would be unacceptable to Canada, just as no one would expect Canada to consider a joint project which had aspects totally alien to U.S. sensibilities. Accordingly, the parties have argued, here and before the NEB, what great expectations are in store for each country by choosing one project over the other and what the counterpart agency of government will be expected to decide. The recent draft treaty and the terms of the 1976 Alaska Gas Act have blunted some of this discussion; it is evident now that, while each regulatory Commission will still reach its own decision, neither agency is likely to act unilaterally, since there are more than sufficient negotiable aspects to warrant keeping all options open. This arrangement likely will remain until it is clear whether a mutually advantageous trans-Canada arrangement is workable.

El Paso's argument, when all the smoke and bombast clears, is founded on its observation that:

> . . . if the United States wishes to get Alaska gas to market on U.S. terms, without the necessary compromises whose economic costs cannot now be measured, it must opt for a trans-Alaska LNG project, just as it did with respect to oil. There can be no assurance that Canada will choose the same overland route as may be recommended by this Commission, nor can there be any prediction as to what trade-offs may be required to obtain Canadian concurrence (Can. Reply Br. 2-3).

The weakness in El Paso's argument, as discussed subsequently, is that it is limited to negative influences on these discussions and the difficulties of implementation and continued operations. Implicit in El Paso's argument is the belief that trade-offs are generally detrimental to our interests rather than mutually beneficial. A fair reading of El Paso's argument is that no reasonable arrangement could or would be reached by the respective parties. 1/ These arguments are also addressed below.

B. Canadian Proceedings and Considerations

Pending before the National Energy Board in Canada at the present time are an application by Arctic Gas (Canadian Arctic Gas) to build the Canadian segments of the Arctic Gas project which is designed to move both U.S. and Canadian gas to market, applications by Foothills, Westcoast, and AGTL to build the Canadian segments of the Alcan project to move only U.S. gas to U.S. markets, and an application by Foothills to build the all-Canadian Maple Leaf project to move only Mackenzie Delta gas to Canadian markets. These applications, for all intents and purposes, have been consolidated, hearings on the consolidated record are proceeding expeditiously, and a decision by the NEB is anticipated in the spring or early summer. As here, these latter applications mutually exclude U.S. gas for a trans-Canada route, since granting either Alcan or Maple Leaf by the NEB effectively forecloses further consideration of Arctic Gas. All principal parties here, in fact, are parties in one way or another before the NEB.

A second hearing inquiry, discussed more fully in Appendix H, Part II, is also underway in Canada. Mr. Justice Berger is conducting hearings into native claims which include those native claims in the Mackenzie Valley and Delta areas through which Arctic Gas' pipeline would pass. 2/ This decision, which is advisory in nature, is expected to be forwarded to the

1/ Alcan may be correct on brief when it states that there is no way short of making Canada a non-sovereign state that a full or rational answer can be given that would satisfy El Paso (Reply Br. p. 2).

2/ The Northwest Territories encompass 1,305,000 square miles, more than double the size of Alaska's 586,000 square miles and almost 5 times Texas' 267,340 square miles. In 1971 its population was 34,805, of whom roughly 24,000 lived in the DOI Northwest Territory Study Area and 9,000 lived in the Mackenzie Valley (ST-27,266-268). General estimates are that 7% are Eskimos and 26% are Treaty Indians, but others also would be interested in native claims. As the population has grown, the percentage of Eskimos and Treaty Indians has fallen. A short history and description of the Northwest Territories is set out in ST-27, DOI's Canada Volume.

Minister of Indian Affairs and then the Governor-in-Council in early spring of 1977. Additional native claims, though not as pressing according to some of the evidence, exist along the proposed Alcan route.

At this point, several of Alcan's and El Paso's arguments should be given a quiet burial. It is just so much cant to suggest that the United States is seeking to dictate anything to Canada through the regulatory process. Canadian Arctic Gas, the Canadian component of Arctic Gas, is seeking a certificate to move not only U.S. gas to market but also large volumes of Canadian gas. It seeks authority in the same way that Maple Leaf seeks authority, and it must prove to the Canadians the value of its proposal to Canada just as each applicant here must prove the value of its proposal to the U.S. Moreover, the decision before Canada will be made by rational men viewing the pros and cons of the proposals on a wide range of criteria, just as it is assumed rational men here will make decisions. 1/

Second, it must be assumed that in the mix of criteria considered by the NEB and ultimately the government of Canada, certain considerations are common to all modern governments. The availability and use of energy resources are the touchstones of a modern society, and no country, including Canada, will suffer their abuse to the detriment of its citizens. Arctic Gas clearly recognizes that only a mutually acceptable and beneficial contractual relationship in the best interests of all the parties concerned would provide the appropriate assurances to Canada that these energy resources would be properly exploited by certificating Arctic Gas. Moreover, given the present state of world energy resources and availability, it can be assumed that more rapid development of known and substantial resources is as important to Canada as to the U.S. and that a time frame for delivering known supplies late into the 1980's is not likely to be a winning position. Alcan's construction scheduling for the delivery of U.S. and Canadian gas is discussed supra.

Third, it is unlikely that native claims will significantly modify the Canadian government's energy decisions. Considerations of the time required for Canadian settlement of the outstanding

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1/ No attempt is made here to address Alcan's arguments that there are no economic benefits to Canada from the Arctic Gas Project (Can. Reply Br. 10). On its face, however, delivering Canadian gas to market cheaper and more quickly, as well as accommodating its largest trading partner, would seem to be positive economic benefits.

Indian claims in the Yukon and Northwest territories has been an issue throughout the proceeding. Succinctly stated, the Eskimos and Treaty Indians residing in the Northwest Territories have claimed the transportation corridor route down the Mackenzie River valley as a part of their lands and have argued that the resolution of all their claims must precede any negotiations for a pipeline. Similar, but not identical, claims are being pursued by Indians in the Yukon for areas involving part of the Alcan route. Several arguments, at least as reported in the press, appear somewhat inflammatory, and others would suggest that a resolution of the Indian claims which would leave the pipeline building decision in the hands of Indian representatives could preclude any exploitation of the Mackenzie Delta reserves for a long period of time. 1/

El Paso, Alcan, and the Conservation Intervenors all argue that resolution of this problem in the Mackenzie Valley is so significant that it would be foolhardy to expect an answer satisfactory to all parties within a time frame compatible with the Arctic Gas project. Absent resolution, or a resolution acceptable to all elements of the Indian population, they argue that it is unlikely that the Canadian government would approve Arctic Gas. Alcan argues that the problems of Alcan in the Yukon are not as significant as Arctic Gas' problem in the Mackenzie Valley because the ". . . mood of the Indian negotiating people is substantially more responsive to the advancement of resolution of the business between them and the pipeline company as well as between them and the government. . ." (quoting Mr. Blair (240/41,938)).2/

As already stated, it must be assumed that no country would defer exploitation of substantial resources, as represented by the Mackenzie Delta and Beaufort Sea hydrocarbon deposits, where lack of exploitation would be detrimental to its people. Since these hydrocarbon deposits are indeed substantial, the decision therefore, that one must logically presume is being entertained by the appropriate Canadian authorities, is one of timing.

1/ See Wall Street Journal - article on 11/1/76 and The Washington Post - article on 11/2/76. A staff brief to Mr. Justice Berger also suggested certain delays if agreement on certain claims was not reached.

2/ Like beauty, "responsiveness" may be in the eye of the beholder.

The question of when Canada will resolve its Indian claims and whether it will do so in a manner which would then permit construction to commence expeditiously cannot be answered on this record, of course. The best that can be done is to give weight to the fact that the negotiations are bona fide, that the investigations of the Berger Commission are the type of fact-finding studies which can lead to prompt decision, and that the Canadian government is not likely to let this troublesome problem fester. When one adds to these considerations the fact that the claims themselves are an outgrowth of the Canadian government's recognition of a general obligation to entertain such claims and to resolve the native rights question, talk of 10 to 15 years delay makes little sense. 1/

Nor are possible threats to operate outside the scope of Canadian law from persons unhappy with the ultimate plan entitled to any weight. There is not the slightest reason to expect that the Canadian government would accede to such obvious pressure any more than any other sovereign state would. The likelihood of Canada deferring the delivery of resources to market on the basis of native claims, if it is otherwise decided that they are needed in its best interest, is minimal. If a Canadian decision were reached not to approve a joint facility, native claims, of course, could be expected to be among the reasons given for a denial.

C. U.S.-Canadian Relations

As an overview, the basic contention of El Paso throughout the proceedings has been that, like all sovereign nations, Canada will always act in its citizens' best interest. Since the "best interests" of the Canadians are not necessarily the "interests" of the U.S., the argument goes that routing any portion of the line through Canada carries with it a substantial risk of Canadian interference with the project and the ability of the United States to move U.S. gas to U.S. markets. This is particularly true, the argument runs, with respect to the restrictive investment and repatriation of foreign investments from Canada, the requirements for so-called "Canadian Content"

1/ In its Initial Brief, El Paso cites at length from the brief of the Berger Commission staff (October 29, 1976) suggesting, inter alia, that socio-economic costs be borne by pipelines and that all routes avoid Old Crow, which is 100 miles from the Arctic Gas pipeline route and had a population of 216 in 1970 (ST-27, P.268).

for goods, labor, and equity participation in business ventures in Canada, and the possible future sequestration of pipeline capacity if needed to meet Canadian energy requirements.

Arctic Gas has argued from the beginning, now joined by Alcan, that a joint project through Canada is not dependent upon a U.S.-Canadian treaty. Their position is that the normal and long-standing relationship between the U.S. and Canada is more than a sufficient basis for assuming stability and rational treatment of a mutually beneficial business enterprise. Arctic Gas particularly argues that El Paso's arguments are beside the point in that the case should be decided on its merits -- obviously favorable to Arctic Gas -- and if the NEB does not approve the Canadian portion, Arctic Gas will then lose (Can. Reply Br. 5-6). The treaty, in its view, regularizes and simplifies the procedures of obtaining joint approvals.

El Paso does not rest by merely suggesting that the Canadian federal government could act overtly in contravention of business arrangements initially approved by it. What it suggests is that the actions of the federal government could be within the law, including a treaty, but still be unreasonable from the U.S. point of view in allocating costs of future capacity, granting applications for line expansion, taxes, and other areas primarily within the ambit of Canadian policy. Simple action in the monetary area, through decreasing the expansion of money supply, it argues, could scuttle Canadian financing. El Paso's argument waxes hot when it addresses the federal government's recent price rises on export gas and its alleged unreasonableness in aiding and abetting disproportionate curtailments to U.S. and Canadian consumers by the provincial government of British Columbia.

The El Paso Canadian Reply Brief is as well crafted a chamber of horrors as this writer has ever seen and would do justice to the standards set by the Marquis de Sade if he had been interested in economics and politics. But that is also its undoing, for the questions so piously raised for the most part are no more than unrealistic speculations which, if valid, might be as applicable to El Paso's Alaskan and Algerian endeavors as to the Arctic Gas and Alcan proposals here to cross Canada. If El Paso can argue to the American consumer that the gas supply from Algeria will remain constant for the next 20 years or that tax treatment by Alaska will remain constant for a similar period, reliance factors which impact most heavily on El Paso, it cannot at the same time expect its arguments against the reliability of Canada to be given much weight. Be that as it may, its innuendoes and arguments are entitled to be considered on the merits, or lack thereof.

There has been a running thread throughout the hearing concerning two recent Canadian actions on hydrocarbon resources which have clearly hurt U.S. interests. Both involve Canadian sales, and both clearly have rankled those who have been hurt. The first was the decision of the Canadian government to collect the economic rent 1/ created by the fourfold increase in world-wide hydrocarbon prices since 1973. The price of Canadian natural gas has been subject to a system of myriad export duties which will have brought its price by January 1, 1977, closer to the commodity level of oil in most markets--$1.94/Mcf or about $11 per barrel oil.

The very Canadian sale raised by El Paso here was addressed by Judge Southworth in El Paso Natural Gas Company, RP72-154, issued August 29, 1974, 2/ as follows:

> The Canadian Federal Government and the Province of British Columbia have undertaken to serve their respective national and provincial interests in conserving their supply of natural gas by providing for prices to domestic as well as export buyers which recognize the commodity value of natural gas in relation to other fuels. They have enacted regulations and created governmental agencies to insure that gas may be exported only upon a finding that it is surplus to Canada's own needs, and at prices which are at all times subject to review and which are required to be at least 5% higher than the domestic price.
>
> There is nothing inherently unreasonable about the idea of using the price of natural gas, an irreplaceable national asset, as a means to discourage its use for inferior purposes. Cf. dissenting opinion of Mr. Justice Jackson in Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 629, 656 (1944) and his concurring opinion in Colorado Interstate Gas Co. v. Federal Power Commission, 324 U.S. 581, 615 (1945).
>
> The Province of British Columbia has apparently undertaken to eliminate undue or 'windfall' profits which might result from its policy by interposing the

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1/ "Economic rent" is often defined as the price paid in excess of that strictly necessary to call forth a given level of production. In many instances, it is collected by the manufacturer or producer as additional profit, in others through taxes, duties, or other government levy.

2/ Order denying exception entered March 18, 1975.

Petroleum Corporation, a government agency, between producers and distributors so that wholesale prices based upon commodity value will be 'distributed between the Petroleum Corporation and the natural gas industry within the Province.' Thus, the record indicates, any excessive profits will presumably go to the provincial government as a kind of severence tax. It has been suggested that a reduction in the use of natural gas for boiler fuel and the like, by reason of this price policy, may operate to increase the volume of gas available for export to the United States.

In fact, the determination in the United States to permit a slower rise of prices to meet the price of competitive fuels has resulted in the economic rent being collected by the consumer. 1/ This is the obvious result of the decision neither to deregulate natural gas sales nor to interpose a regulatory taxing presence between the seller and the consumer.

There of course is little justification from the American consumer's point of view for the action of the British Columbia government in forcing U.S. consumers to absorb the entire brunt of a Westcoast curtailment. Westcoast was unable to deliver its full contractual volumes because of field production failures. The British Columbia government, through various semi-public corporations it controlled, ordered that all British Columbia customers would be served from available supplies before Westcoast exported any Canadian gas under the contracts to U.S. customers. (See exposition in El Paso case, supra, p. 7; RP72-154.) There is no question that curtailments of 150,000 Mcf/d out of the firm delivery instead of the 90,000 Mcf/d *pro rata* curtailment from the contract entitlement of 800,000 Mcf/d was less than fair to the U.S. customer, even if permitted under the *force majeure* clause. Even taking into account that the volumes involved may still be delivered and that no determination is of record as to whether the Canadian decision weighed the markets' ability to absorb these curtailments, the action must be considered unwarranted. 2/

1/ In the intrastate market, new sales at market value give the economic rent to the producer.

2/ Other acts by which Canada has attempted to establish a greater degree of control over its magazines, newspapers, investments, or land are hardly indications of unfriendly attitudes, any more than other countries' trade laws or use of voluntary quotas.

As a general matter, while the arguments suggesting Canada's unreliability as a business partner have been couched in euphemisms suggesting no more than a sovereign's acting in its best self-interest, even in this watered-down language they do a great injustice to the historical facts. 1/ Acts of "best self-interest" are usually associated with acts of unilateral abrogation of business contracts, expropriation of one's neighbor's property, discriminatory taxation, confiscation of dividends owed and payable, and a host of other acts not normally associated with a friendly country with whom we have had long-standing cordial relationships. Even if it is assumed that a Canadian government would come to power predisposed to act unreasonably, such imprudence could be countered with equally unsavory activities on the part of the U.S. The point is that the multifaceted world we live in requires that credence be given to constancy in relationships extending back almost 200 years. Staff is not "simplistic", as argued by El Paso, for relying on the historical facts. No one can guarantee the future, but here we are only called upon to assume that the past is an indication of what will happen. 2/

Finally, it is not irrelevant to U.S. interests when Canada brings Frontier gas to market. Whether a political decision is reached to continue, or even expand, exports is not the same question as whether underlying reserves are attached that would make a favorable decision viable. Given what is represented as the existing Canadian view of Canada's natural gas supplies, absent attaching substantial Canadian reserves, no affirmative decision could be made to export additional gas even if the NEB were so inclined. Attaching Canadian Frontier gas, therefore, can only help the U.S. prospects; certainly the climate will be improved even if the decision never is made.

1/ In fact, in its Opening Brief, El Paso carefully and respectfully states that its sole purpose is to raise those problems caused by the "presence of state power" (p. 2).

2/ The story is told of how a scorpion mortally stung a turtle which had rescued the scorpion from drowning during a flood and was ferrying the scorpion to dry land. In disbelief, the dying turtle asked the scorpion, which had also sealed its own death by drowning, why it had stung him. "I'm not rational" was the reply. Both the U.S. and Canada must be presumed rational and must be cognizant that their best interests will not be served by mutual distrust and antagonistic acts.

D. Ad Referendum Treaty

If the appropriate U.S. and Canadian regulatory functionaries approve a trans-Canada facility for U.S. gas, whether or not commingled with Canadian gas, 1/ it is highly unlikely that Canada would not be interested in the economic viability of the project. Presumably, facilities built in Canada will be primarily owned by Canadians and presumably Canadian businessmen are governed by the same motives that govern others -- expansion of facilities to carry additional volumes of gas is profitable and is good business. As Arctic Gas argues, there is simply no reason to believe that, in a situation where facilities can be relatively easily expanded, a course of action inimicable to good international relations would needlessly be followed. While it might appear simplistic, there is no reason now discernible to suggest that Canada would act in any manner not consistent with business as usual. In other words, a treaty which merely spells out those reasonable practices of ordinary good business relationships does not add substantially to the overall expectation that the relationship is workable.

In any event, a treaty has been negotiated. 2/ Like all treaties, such as the ones surrounding the St. Lawrence Seaway, it would be expected that amendments would be made from time to time, just as contractual agreements between partners are amended from time to time. Given some of El Paso's positions, it is most likely that treaty clauses will be added to resolve future allocation of expansions and possibly even that the rate determination will be on a just and reasonable basis, as those terms are normally employed. 3/ Thus, all would share equitably in all expansions resulting in either savings or costs.

1/ Arctic Gas and Alcan must be considered as having identical positions. If substantial gas is found in Northwest British Columbia or the Yukon, that gas would be to Alcan-Foothills as Mackenzie Delta gas is to Alaskan Arctic-Canadian Arctic.

2/ Article II, Section 3 already provides:

> "3. Each party undertakes to facilitate the expeditious issuance of such permits, licenses, or other authorizations as may be required from time to time for the import into, or export from, its territory through a Transit Pipeline of hydrocarbons in transit."

3/ It is not believed that any treaties are in effect or contemplated with any of the other countries from which applications to import gas, much less transit gas, are now on file with the Commission.

Treaties add another degree of regularity to a commercially viable situation. A treaty also narrows areas of future differences. To the extent that the language of an essentially commercial treaty is not satisfactory, there is little reason to doubt that it will be easily and quickly amended.

The above discussion, primarily limited to political considerations, represents the smallest part of the scholarly debate on Canadian law which took place during the hearing. The testimony of Messers. Williston, Robinette, and Geller was a legal seminar on the nuances of Canadian constitutional law rather than a pedantic proof of foreign case law or a brouhaha over political considerations. Several of the briefs, such as El Paso's Initial Brief, have sections dealing with the history of Canadian constitutional law which could serve as a primer for most courses on the subject (pp.4-11). Unfortunately, the political dispute ultimately elbowed its way into the limelight and covered up both the high level and style with which this debate over Canadian law was conducted by all parties.

XII

NET NATIONAL ECONOMIC BENEFITS

Net economic benefit studies are cost-benefit analyses. They attempt to measure and quantify the total costs and total benefits of a project over its life, with both costs and benefits discounted back to a common project start. The "net benefits" (or net costs) equal the difference between these two discounted amounts (Exhibit AA-127, p.5; Exhibit EP-231, p. 113; 146/23,817-820). Accordingly, the purpose of a net "national" economic benefit (NNEB) study is to determine, for a particular project, the relationship between costs and benefits on a national scale. To this writer's knowledge, this is the only NNEB analysis filed before the Commission or, for that matter, before any administrative agency.

In the course of these proceedings, several NNEB studies were presented. Common to all of these studies, and endorsed by all parties, is the finding that any of the three proposed projects, if certificated, would provide net economic benefit to the United States. Thereafter, unanimity ceases. If this were not a competitive hearing, the finding of a net benefit would, for all intents and purposes, end the inquiry. 1/

A. The Studies

1. The DOI Study

The model upon which each of these NNEB studies was predicated was developed by the Department of the Interior (DOI) and included as part of DOI's presentation in its Report to Congress (Exhibit EP-231). The DOI NNEB study purported to evaluate the feasibility of a gas pipeline through Canada following a route more or less similar to that proposed by Arctic Gas. 2/ Two alternatives were also considered by DOI, the first an Alaska-LNG system similar to that proposed by El Paso, hereinafter called El Paso, and the second a land route down the Alyeska corridor to Fairbanks, then eastward and south along the Alcan highway. 3/ For the Arctic

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1/ The comparisons, therefore, are all in pluses -- i.e., $2 is a greater benefit than $1. The name of the game for each study was to show a higher number for itself and a lower number for its competition. An increase in cost to a competitor is as good as a decrease in cost or increase in benefits for oneself.

2/ This section of Ex. EP-231 was supported by Dr. Robert Anderson of DOI. He was subjected to extensive cross-examination and the section was admitted in evidence.

3/ The subsequently proposed Alcan project essentially adopted the routing last described above.

Gas hypothetical, NNEB was estimated at $8.7 billion. For the El Paso alternative, the figure was $7.8 billion. The Fairbanks-Alcan alternative, very close to the route upon which the Alcan project subsequently was modeled, was found to provide a NNEB of an even greater magnitude (Exhibit EP-231, p. 122, Table 22). Between the Arctic Gas and El Paso "hypothetical" systems, the difference in NNEB was primarily attributable to relatively lower fuel shrinkage, lower U.S. share of the transportation cost, and lower cost of a displacement plan enjoyed by the Alaska-Canada system (Id., pp. 125-126).

2. The Staff Studies

In its original FEIS (ST-18), Staff computed two sets of comparative NNEB's. On pages I-A14 through I-A16 of that exhibit, Staff utilized DOI's costs and assumed a uniform flow of Prudhoe Bay gas for each of the three systems, denominated Improved 1/ El Paso (corresponding to "Improved Alaskan LNG" in the DOI analysis), Alaskan Arctic ("Alaska-Canada" in the DOI study), and Fairbanks Alternative ("Fairbanks-Alcan" in the DOI Study). Later, beginning on page I-C21 of that exhibit, Staff utilized the applicants' (Arctic Gas and El Paso, at the time) costs, as well as the applicants' proposed flow rates, which differed from one another. Finally, and most significantly, Staff restated the NNEB comparison showing five systems: Alaska-Canada with a western leg, Alaska-Canada without a western leg, Improved El Paso, Fairbanks-Alcan, and Northwest with a western leg. DOI's costs were used except in the case of Northwest. The results are presented in Staff's supplements to its FEIS, admitted as Exhibits ST-53 and 54. In Table II-3-1 of Exhibit ST-54, Staff develops separate NNEB's for each system, using (1) both "high" and "low" estimates of gas supplies available in the lower 48 states and (2) both $12 and $8 per barrel oil. Naturally, the combination of low gas supplies and expensive oil will produce the highest NNEB for each system.

Table II-3-1 2/ shows that the NNEB for Alaska-Canada with a western leg is given at $9.444 billion, assuming *inter alia*: 3/

(a) $12 per barrel oil
(b) "low" domestic supply of gas
(c) an Alaskan gas flow of 2.5 Bcf/d from mid-1982 through 1985

1/ "Improved" refers to the decrease in shrinkage at the liquefaction plant (147/23,912).

2/ Reproduced at the end of this section.

3/ Staff estimated Arctic Gas' NNEB without a western leg at $9.7 billion. The disagreement between Arctic Gas and Staff as to the advisability of a western leg has been discussed elsewhere in this decision and resolved in favor of Arctic Gas, i.e., the western leg has been retained. Review of Staff's NNEB studies will proceed on that basis.

(d) 3.5 Bcf/d thereafter through 2001
(e) Mackenzie Delta flow of 0.5 Bcf/d from mid-1982 through 1985
(f) 0.9 Bcf/d thereafter through 2001

Using the same Alaskan gas delivery rates, oil prices, and domestic supply assumptions, Staff computes a NNEB for El Paso of $9.1 billion and a NNEB for Staff's hypothetical Fairbanks-Alcan system (here, unlike DOI, the actual Alcan proposal) of $9.8 billion. Alcan's (Northwest) NNEB was determined to be $6.9 billion, based on an Alaskan flow of 2.4 Bcf/d for 20 years, but, as Staff admits, this difference in flow rates makes meaningful comparison between the Alcan NNEB and the others difficult, if not impossible. Staff suggests, however, for some unexplained reason, that Alcan could approach the $9.8 billion attributed to the Fairbanks-Alcan hypothetical system if it could achieve a delivery rate of 3.5 Bcf/d without looping-- 0.4 Bcf/d more than Alcan claims its line can carry even with 113% additional fuel costs to achieve a maximum 3.1-Bcfd flow.

Both the DOI and Staff studies elicited reaction from Arctic Gas and El Paso. Alcan reportedly initiated a NNEB study of its own, but, on reflection, decided to tender nothing for the record (Alcan Reply Brief on NNEB, p. 17-18). The Arctic Gas and El Paso studies were, of course, keyed to their actual system expectations and not to hypotheticals. As expected, each study proclaimed its sponsor's project as the one most likely to provide maximum NNEB to the United States.

3. The Arctic Gas Study

Arctic Gas' NNEB study was admitted into evidence as Exhibit AA-127. It is styled a comparison of Net National Economic Benefits of Arctic Gas and El Paso Alaska Projects and includes a critique of the foregoing DOI and Staff NNEB analyses.

Key conclusions are found in Table 1, on pages 3 and 6 of that Exhibit. That table shows an Arctic Gas NNEB ranging from $6.9 billion (in dollars discounted at 10% to January 1, 1977) for the 2.25-Bcf/d "no expansion" 1/ case to $11.4 billion for the 3.2-Bcf/d case. For El Paso (using El Paso's costs), the comparable range is $4.9 billion (at El Paso's projected rate of 2.4 Bcf/d) to $7.1 billion (at 3.2 Bcf/d). The composition of the costs and benefits reflected in Table 1 are shown on Sheet 1

1/ Wherein Mackenzie Delta deliveries do not rise above 1.0 Bcf/d.

of Schedule 1 of Exhibit AA-127. Included as costs thereunder are U.S. taxes, income and "other" (primarily property). Included as benefits for Arctic Gas are "Maintenance of Canadian Imports" and, for both Arctic Gas and El Paso, "Benefit of Energy Independence." As shown below, apart from DOI's inclusion of "Energy Independence" as a benefit, each of these components mentioned above represents a departure from the NNEB methodology adopted by DOI and Staff.

4. The El Paso Study

In Exhibit EP-275, El Paso presents its rejoinder to the Arctic Gas NNEB study (Exhibit AA-127)-- bascially an attack on Arctic Gas designed to reduce the gap shown in both the DOI and Staff studies. In Table 1 of Exhibit EP-275, El Paso compares the 2.25-Bcf/d no-expansion 1/ case for Arctic Gas with El Paso's 2.4-Bcf/d case. In the benefits category, El Paso begins its paring down by reducing both systems by $1.1 billion, which it ascribes to "Energy Independence." Second, Arctic Gas' benefits are stripped of 0.7-1.4 Bcf/d related to "Maintenance of Canadian Imports." Regarding costs, El Paso first adjusts all costs to reflect 5% inflation (Arctic Gas used a 7% rate). 2/ Third, El Paso removes U.S. taxes as a cost item for both systems, producing a positive impact of $0.9 billion for itself, $0.2 billion for Arctic Gas. It is El Paso's position that U.S. income taxes should be treated as transfer payments rather than as costs. Fourth, Arctic Gas' costs are inflated to reflect Arctic Gas' current and deferred Canadian income tax liability. El Paso here contends that Exhibit AA-127 treats Arctic Gas' current liability only and thus fails to recognize as a proper cost those taxes which Arctic Gas will be collecting from U.S. ratepayers but which, under Canadian law, it will not have to forward to Canadian taxing authorities for 3½ years (231/40,212). This adjustment amounts to a modest reduction of $0.2 billion in Arctic Gas benefits. Finally, El Paso increases Arctic Gas' costs by $1.1 billion in relying on DOI's prediction (Exhibit EP-231, p. 143) that Arctic Gas would experience a delay in its construction schedule, relative to El Paso, of 1 year. 3/ Bottom-line

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1/ Assuming Mackenzie Delta flow of 1.0 Bcf/d.

2/ For the Arctic Gas project, Arctic Gas' own underlying cost estimates were used.

3/ DOI assumed schedule slippages of from 12 to 36 months for Arctic Gas and 6 to 18 months for El Paso. Accordingly, El Paso calculated a mean difference of 1 year in its own favor (231/40,195). As found supra, in the Construction section, Arctic Gas will not experience a year's delay, although it will experience some increased costs.

tabulations in Table 1 of Exhibit EP-275, not surprisingly, give El Paso an NNEB advantage over Arctic Gas, $6.8 billion to $5.9 billion. 1/

5. Alcan's Position

As mentioned above, Alcan submitted no NNEB study of its own. Not surprisingly, Alcan contests the reliability of all of the NNEB studies as tools for measuring the relative economic appeal of the three projects. Alcan's reasons include the following: (1) certain studies compute NNEB for hypothetical transportation systems which are not sufficiently analogous to any of the three projects as actually presented; (2) many of the assumptions upon which these studies are founded have not been, nor can they be, substantiated on the record; (3) the results of the studies are highly sensitive to minor changes in many variables which must be projected into the future; (4) all of the studies fail to quantify the costs and benefits associated with environmental impact and potential outages, despite the admitted significance of these factors, 2/ and (5) the demonstrated potential for mathematical and programming error makes these studies further suspect. 3/

1/ In Tables 2A and 2B of Exhibit EP-275, El Paso compares the Arctic Gas project with its own on the basis of 2.4 Bcf/d (Table 2A) and 3.2 Bcf/d (Table 2B) delivery rates for Alaskan gas. The same adjustments which El Paso made in Table 1 are evidentally carried forth, except that here El Paso assumes an Arctic Gas schedule delay of 1½ years, based upon the Green Construction Company's risk analysis of the Arctic Gas project (231/40,216). Additionally, El Paso incorporates Green Construction's $0.9 billion projected cost overrun for Arctic Gas and assumes a Mackenzie Delta flow of but 0.5 Bcf/d, which adversely affects the U.S.-Canadian allocation of cost responsibility on the Canadian Arctic system. The result is that, in Table 2A, Arctic Gas' NNEB is lowered to $5.4 billion, while El Paso's NNEB remains at $6.8 billion. In Table 2B, Arctic Gas' NNEB is raised to $7.8 billion; El Paso's NNEB becomes $9.7 billion. Each additional assumption made by El Paso here as to Arctic Gas overrun and Mackenzie Delta gas volumes has been found not warranted.

2/ Exhibit EP-231, pp. 118, 129; 201/34,381; 206/35,366.

3/ 146/23,813-815.

As a matter of form, Alcan criticizes Arctic Gas for using what it finds beneficial in the DOI-Staff studies and overlooking or rejecting what it finds uncomplimentary, e.g., rejecting Staff's conclusion that the Fairbanks-Alcan hypothetical system would provide more positive NNEB values than either the Alaska-Canada or El Paso alternatives but endorsing Staff's finding that the net benefits associated with the actual Alcan proposal are less than those provided by the Alaska-Canada hypothetical system.

If different NNEB studies are to be compared, then, in Alcan's view, the "least unreliable" comparison would be between the actual El Paso and Arctic Gas proposals, as analyzed by Staff in its original NNEB study (Exhibit ST-18 at I-C21, Table I-M) and Staff's analysis of Alcan in its second study (Exhibit ST-54, Table II-3-1). Assuming $12 bbl. oil and high non-Alaska supplies, Alcan's NNEB surpasses the others. 1/

B. Discussion

Accepting the findings in all of the NNEB studies as proof that each project will provide net national economic benefit to the United States, the only task remaining is to somehow determine, if possible, a relative ranking of the three from an NNEB standpoint. Alcan's misgivings notwithstanding, the DOI model can be used for this limited purpose so long as reliable input data are used. Precise dollar determinations are not necessary if it can be reliably deduced that a margin favors one applicant over the others.

The only record NNEB comparison between Alcan and the other projects is contained in Exhibits ST-53 and ST-54. 2/ Therein Alcan finishes dead last. As Staff observes at page 10 of its NNEB Brief, Alcan, although a late entrant in these proceedings, had ample time to undertake a study which would "force" the competition into Alcan's own supply mold, yet chose not to do so. 3/ Such a study might well have improved Alcan's NNEB standing vis-a-vis Arctic Gas and El Paso. It is highly doubtful,

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1/ It must be remembered, however, that the assumed Alcan flow is 2.4 Bcfd, while the Arctic Gas and El Paso flows are each assumed to be 2.25 Bcfd.

2/ Any comparison between Alcan and the other applicants is handicapped because the pipeline capacity of Alcan and its competitors is so dissimilar.

3/ Alcan's staff, of course, had few resources left, having mounted a major application without notice, having prosecuted a case with a prior record almost unknown to it, and having been attacked by both Arctic Gas and El Paso. On top of this, the Presiding Judge had already indicated, in all candor, certain reservations about the value of the studies then of record.

however, that, under any assumed deliverability, the Alcan project could approach the $9.8-billion NNEB which Staff ascribes to its own Fairbanks-Alcan system described in its FEIS. As explained on pages II-12 and II-13 of Exhibit ST-53, overtaking Fairbanks-Alcan would in effect force Alcan to produce gross benefits over investments in a 6-to-1 ratio. Given the 3-to-2 benefit/cost ratio of the Alcan system as presented, Staff finds such a feat quite unlikely. That the Alcan project could surpass the $9.4-billion NNEB attributed to Arctic Gas or even the $9.1-billion NNEB attributed to El Paso must also be found highly implausible.

The choice is thus between Arctic Gas and El Paso. It is not a particularly difficult one. As discussed above, Tables 1, 2A, and 2B of El Paso's Exhibit EP-275 all penalize Arctic Gas for assumed delay in completing its project. Table 1 estimates the relative delay at 1 year, at a cost to Arctic Gas of $1.1 billion. In Tables 2A and 2B, the delay balloons to 1½ years, and the attendant cost increase indicated in Table 2A is $1.6 billion (231/40,225) or $2.1 billion in Table 2B (231/40,226). The Construction and Geotechnical section of this decision finds that additional investment of some $210 million and development of certain contingency plans will enable Arctic Gas to meet its presently forecast construction schedule. Accordingly, El Paso's NNEB calculations must be revised to reflect this assumption. Table 1 of Exhibit EP-275 shows the difference between Arctic Gas and El Paso as $0.9 billion. Adding back the $1.1 billion which El Paso sought to eliminate produces a difference of $0.2 billion, this time favoring Arctic Gas. Similarly, excising the $1.6-billion and $2.1-billion costs assigned to Arctic Gas in Tables 2A and 2B, respectively, more than offsets the respective $1.4-billion and $1.9-billion advantages attributed to El Paso in those tables. Thus, using El Paso's own study and adjusting only one variable to reflect the weight of the evidence, the NNEB of the Arctic Gas project is perceived as superior to that of the El Paso project.

This superiority is further enhanced by favorable resolution of other contested items. To begin with, it should be noted that upgrading the Arctic Gas flow rate in Table 1 of Exhibit EP-275 from 2.25 Bcfd to 2.4 Bcfd, thereby making it comparable to the El Paso flow rate used in that table, produces Arctic Gas benefits on the order of 4% to 4½% (231/40,219), which Arctic Gas converts to $0.6 billion (231/40,219-221). Tables 2A and 2B should be adjusted to omit the effects of the $0.9-billion cost overrun predicted by Green Construction, since this increase was found unwarranted in the Construction and Geotechnical section of this decision, supra. Further, Mackenzie Delta gas flow has been pegged at 1.0 Bcfd in the first year of operation and 1.5 Bcfd in the fifth year. (See Gas Supply section, supra.) These estimates reduce El Paso's estimate (based on a Mackenzie Delta flow of 0.5 Bcfd) of the percentage of Canadian Arctic costs which would be allocated to U.S. customers of Canadian Arctic. 1/ Other salient matters affecting NNEB are treated below, seriatim.

1. Benefits

Assuming the same market value 2/ of gas for each of these three systems, the primary benefit for each system will be determined by the volume of gas delivered. In this capacity, Arctic Gas has a decided edge, since its system will have lower shrinkage. (See Operations section of this decision, supra.) Tangential benefits are also possible.

1/ In a correlative argument, El Paso postulates that, were Arctic Gas able to take delivery of 2.25 Bcfd from Mackenzie Delta, as it anticipates, then only 2.25 Bcfd of capacity in the Canadian Arctic line would remain for Alaskan volumes. The effect of this would be to give El Paso, at 3.2 Bcfd, a clear edge in NNEB. Of course El Paso flatly disputes Arctic Gas' ability to attach the 2.25 Bcfd of Mackenzie Delta gas. In any event, there is no reason to think that Canadian Arctic would be unable to expand its system to accommodate a 3.2-Bcfd flow from Alaska as well as 2.2 Bcfd from the delta.

2/ All parties, save Staff, apparently accept the DOI valuation of $2.62 per Mcf for natural gas (Exhibit EP-231, pp. 65, 123, 125). Staff, by contrast, computes a slightly lower value by establishing, by regions (Exhibit ST-18) and states (Exhibit ST-53), a nationwide allocation of non-Alaskan and Alaskan gas in an effort to maximize the annual gross benefits of gas consumption. (See Exhibit ST-53, pp. II-2 to II-3 and Staff witness Sewell's testimony at 146/23,827-830.)

a. Canadian Exports

In Schedule 1 of Exhibit AA-127, Arctic Gas has calculated benefits ranging from $0.739 billion to $2.996 billion which are attributable to Maintenance of Canadian Imports. 1/ Arctic is here operating under the theory that the transportation of Mackenzie Delta-Beaufort Sea gas by Canadian Arctic will enable Canadian supplier-shippers to meet their current and projected domestic service obligations and so ease the possible future reduction of exports to the United States which may be imposed as a first step in protecting the integrity of service to Canadian customers. In determining the attendant benefits, Arctic Gas evidently assigns to each Mcf of gas imported from Canada a net value equal to the difference between the net value of gas at the average U.S. city gate ($2.62 per Mcf) and the currently effective border price of Canadian exports to the U.S. which, but for the Arctic Gas project, would be denied export licenses by Canada. Volumes may vary according to (1) the volume of Canadian gas to be produced in the Beaufort Sea-Mackenzie Delta region and shipped via Canadian Arctic and (2) the degree, if any, to which Canadian exports to the U.S. would be restored following completion at a later date of a Canadian-only line to transport such gas south. This assumes the absence of the projected earlier deliveries available for Canadian gas to Canadians under Arctic Gas' proposal In other words, if it can be assumed that export volumes once curtailed would not be reinitiated following completion of a Canadian-only line, then the benefit associated with maintaining these exports is commensurately greater than if exports were to be restored immediately following completion of such a line.

El Paso responds that such claim presupposes (1) that Arctic Gas will be built before the Maple Leaf Project, (2) that Canadian exports would diminish without certification of the Arctic Gas Project, and (3) that Canada will charge less than the full opportunity cost for exported gas. El Paso then submits that at least one, and probably all, of these suppositions is likely to prove false, thereby undermining Arctic Gas' contention and obviating any associated NNEB. It is El Paso's stated belief that construction delay and native claims may prevent early construction of the Arctic Gas system, if authorized; that the pattern of discontinuing Canadian exports is too well established to be affected by the Arctic Gas project (especially if Mackenzie Delta impact is small); and that there is no reason to believe the Canadian government will not exact all it can from U.S. purchasers of export gas. Staff and Alcan share the sentiment of El Paso in these respects.

1/ Imports to the U.S.; exports from Canada.

Perhaps this issue, more than any other, epitomizes the degree of speculation characteristic of each of these NNEB analyses. To begin with, it is clear that Arctic Gas can bring Mackenzie Delta gas to Canadian markets sooner than the Maple Leaf project if it is assumed the Alcan project receives authorization to carry Alaskan Gas to the lower-48 states. (See Financial section, infra.) On the other hand, where such authorization is instead awarded to El Paso, this advantage is nonexistent, i.e., there is no way of knowing whether El Paso or Maple Leaf will be the first to deliver gas to their respective markets. Arctic Gas' claim that its project will facilitate earlier stabilization or renewal of Canadian exports is conditioned accordingly. As found earlier, El Paso's concern over native claims litigation (see Canadian Law section, supra) is grossly overrated, as is its obsession with Arctic Gas' construction schedule.

Despite Arctic Gas' assurance that Canada feels the obligation to continue, if it can, the exportation of Canadian gas to the United States, the record suggests that Canadian policy is at best unsettled on this point. What is clear is that until recently, no additional exports have been licensed by the NEB (since 1971), and the recent experience of Montana Power Company (Exhibit ST-43) gives the impression that such exports will be phased out as licenses expire. 1/ There is testimony in the record, moreover, to the effect that the Canadian government intends to adopt pricing policies which would eliminate the differential between Canadian export gas and alternate fuels in the lower 48 states (147/23,976-977). It is highly likely that Canada will continue its policy of pricing its natural gas at the border so as to command the highest price and yet still be competitive with alternative fuels. The $1.94 current price is certain to rise to reflect this policy. See also discussion in the Displacement section, supra.

On this record, maintenance of Canadian exports is not sufficiently assured so as to result in benefits favoring any of the applicants in an NNEB study.

1/ On January 18, 1977, the FPC issued an Order Authorizing Limited Term Importation of Natural Gas in Columbia Gas Transmission Corporation, Docket No. CP77-126. Columbia is thereunder permitted to purchase 250,000 Mcf/d from Trans-Canada for a period of 60 days. The order states that, while the NEB had not at that time issued an export license for such gas, Columbia expects such permission to be forthcoming. Id. at 2.

b. Energy Independence

Both the Arctic Gas and DOI studies include as a benefit a reduced need for oil storage as the result of Alaskan gas deliveries. 1/ The testimony of El Paso's witness Nathan at 231/40,210-211 is persuasive evidence to the contrary. Witness Nathan states in substance that the expected supply of natural gas from Alaska is too small to have an appreciable impact on the need for investment in oil storage facilities. Furthermore, there is of course no one-to-one correlation between oil and natural gas such that it can be presumed that one stands in lieu of the other. Natural gas is not feasible as a substitute for gasoline. Also, see discussion in the Financial section infra.

c. Employment (And the Multiplier Effect)

El Paso is clearly justified in its emphasis of the superior degree (vis-a-vis the other projects) to which it will provide jobs for American labor and utilize American-made products. Not only will more Americans work on the El Paso project than on either of the trans-Canadian projects, but, because of the nature of the El Paso project, it will draw upon a greater variety of labor than the others. 2/

The advantage which it enjoys in this respect is even more important to El Paso when the multiplier effect is considered. The multiplier effect is the additional impact caused by the further expenditure of the same dollar. One example of a multiplier effect involves a large shipyard going into production in a large unemployment area. Dollars paid out as new or additional wages serve to enhance the spending power of the workers and their families. As the community grows, more service-related jobs are created. the overall result is that the economy of the entire area is boosted.

One of the primary difficulties with the DOI model is that it avoids treatment of a multiplier effect as a variable. Staff and Arctic Gas penalize the El Paso project in like fashion. Several

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1/ According to Arctic Gas' NNEB study, energy independence accounts for benefits of from \$1 to \$1.5 billion. It adds approximately \$0.1 billion more to the NNEB of Arctic Gas than it adds to the NNEB of El Paso (Exhibit AA-127, Schedule 1).

2/ The El Paso project contemplates U.S. construction and operation of ships, marine terminal facilities, and liquefaction and regasification plants, which the others do not.

reasons are advanced. On questioning from the bench, DOI's witness Anderson, who sponsored the DOI study, advised that DOI's decision to ignore the multiplier turned, first, on its assumption that, for the construction of one of these systems to affect the economy, the investment in that system has to be in addition to other investment in the U.S. economy; DOI is of the opinion that investment in these projects will not be incremental but will instead be a substitute for investment elsewhere, such that the economy experiences no net gain (173/28, 503). Second, Dr. Anderson instructs that, even where the investment is incremental, it may in fact do more harm than good if, as is possible, the economy is in a state of full or near-full employment. Investment under those conditions would be inflationary with no offsetting benefits, according to Dr. Anderson (173/28,504).

Like DOI, Staff is evidently unwilling to assume that these investments will be incremental in nature or that the economy will be in a state of less than full employment during the construction and, to a lesser extent, operation periods of these projects (Exhibit ST-53, page II-7; 148/24,044-047). 1/ Staff adds that omission of the multiplier is not improper since agencies responsible for fiscal and monetary policy can take actions in the future to offset, independently of the FPC action, any predicted secondary effects (Exhibit ST-53, pp. II-7 to II-8). These "actions" are not enumerated.

Arctic Gas would discount El Paso's reliance on the multiplier effect by reference to schedule 2 of its Exhibit AA-127, which purportedly shows that, over the life of the projects, Arctic Gas' deliveries of Alaskan gas will exceed El Paso's by 1.2 Tcf, and then to Item by Reference NB-P, pp. 8-89 to convert this volumetric difference to one million man-years of employment. Further, assuming that the Arctic Gas project will facilitate release of from 2.2 to 20 Tcf of Canadian Gas for export to the U.S., Arctic Gas calculates than an additional 2 to 17 million man-years of employment will be protected.

It is most difficult to accept the rationale of the DOI and Staff witnesses in support of excluding the multiplier effect. No challenge is levied against the principles upon which their position is founded. Their assumptions about the sources of investment and the state of the economy, however, defy common sense.

1/ Staff witness Goldstein is of the opinion that somewhere between 4% and 6% unemployment constitutes full employment (148/24,047). He also recognized that unemployment in this country currently runs somewhere between 7% and 8% (Id.).

The Financing section of this decision, infra, chronicles the extent to which these sponsors must go to generate financial backing for their respective investment in the Alaska projects. To characterize the investment in such projects merely as displacement of investment elsewhere--investment which would be job producing--is without record support. Further, the experience throughout this century indicates that it would be ill-advised to conclude that the United States will be in a state of full employment during the construction period contemplated here. The same reservation holds true where only the industries affected by these projects are considered. Hence, it follows that ignoring the multiplier effect in NNEB analysis skews the results of such a study against that project which promises to stimulate greater employment, in this case El Paso. 1/

Determining the existence of a multiplier effect is one thing; quantifying such a phenomenon is quite another. Early in the course of these proceedings, El Paso's witness Dr. Robert Nathan speculated that about 750,000 man-years of employment would be provided through the El Paso project, if primary (direct construction), secondary (providing goods and services to the project), and induced (providing goods and services to the community) employment are all taken into account (64/9,761-762). For Arctic Gas, the corresponding figure was about 400,000 man-years (Id.), but this would of course be reduced to reflect Arctic Gas' subsequent elimination of the Northern Border pipeline east of Chicago and the ITA(A) western-leg pipeline from the 49th parallel to Los Angeles. Since it is presumed that the dollar impact attributable to this multiplier effect has been reflected in the NNEB analysis performed by El Paso in Exhibit EP-275, it is unnecessary to make any further adjustment.

Looking at last to the Arctic Gas retort, it is clear that the reasoning here is certainly suspect, if not specious. It has already been found that maintenance of Canadian exports cannot be assumed nor counted as a benefit for Arctic Gas. In any event, it cannot obtain a benefit by assuming lower prices. Arctic Gas' reliance on the 2- to 17-million man-years of employment which

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1/ There is a large body of economic philosophy concerning the appropriate treatment of multiplier effect in cost analysis modeling. For an extensive discussion of both the philosophy and the difficulties in treatment, see the research study, Efficiency in Government Through Systems Analysis, McKean, 1958, p. 158, et seq., a monograph published by the Rand Corporation.

such imports will allegedly provide to U.S. labor is misplaced. With respect to the additional man-years of employment which Arctic Gas attributes to its larger volume of delivered Alaskan gas, it should simply be observed that Arctic Gas has failed to demonstrate how this phenomenon will come about. Item by Reference NB-P attempts to link a volume of gas with employment in the industrial sector of the economy. It is not inconceivable, however, that, during the bulk of the period over which Alaskan volumes will actually be delivered, all natural gas, including Alaskan volumes, will be devoted exclusively to home heating and other residential uses. Under this scenario, man-years of employment in the industrial sector would be virtually unaffected. 1/

2. Costs

Primary cost components include the wellhead price of gas (uniform for all three applicants), associated gathering and producing costs, capital costs (including working capital) and operation and maintenance expenses incurred in connection with movement of that gas to market. In Exhibit EP-275, El Paso impliedly concedes that these costs (excluding capital cost overruns and the expense associated with delay) will be less for the Arctic Gas system than for the El Paso system. Proper treatment of taxes occupies a great deal of space in the NNEB briefs of both Arctic Gas and El Paso.

a. U.S. Taxes

El Paso, DOI, and Staff all treated Canadian income taxes as costs, U.S. income taxes as transfer payments. Arctic Gas viewed both Canadian and U.S. income taxes as costs. In support of its position with respect to U.S. income taxes, Arctic Gas offered three arguments: (1) U.S. income taxes compensate the U.S. government for services rendered to each project; (2) these taxes compensate for the cost of "externalities," including adverse environmental impact; and (3) payment of these taxes distrubs the overall allocation of resources, thus representing a cost to the nation. Of these three, the latter two do not lend themselves to quantitative analysis and should not be given weight in a classic NNEB

1/ Except with respect to the natural gas industry itself.

study. 1/ Regarding compensation for government service, Arctic Gas' witness J. Brickhill posited that the El Paso project would cause the U.S. government to incur cost in connection with use of the Coast Guard in Prince William Sound, FPC regulation during the life of the project, and use of the Postal Service (206/35,359-361). Arguing that these services are de mimimis relative to the federal tax revenues generated, 2/ El Paso convincingly points out (1) that El Paso's tanker fleet will be small in comparison with the oil tanker fleet, such that Coast Guard costs attributable to the El Paso tankers will not be great, (2) that FPC expenses are covered by the prescribed and paid filing fees, and (3) that postal costs are paid by private parties as they are incurred. While there may be other ways in which the various projects cause governmental expense (e.g., road construction and maintenance; municipal sewage, additional police facilities and personnel and/or national security and inspection coverage), the costs are unknown and, it would appear, relatively inconsequential. As DOI observes, ignoring them is not likely to bias this proceeding in favor of either of the two hypothetical systems (Alaska-Canada and El Paso) studied (Exhibit EP-231, p. 118). Treating U.S. income taxes as transfer payments rather than costs is consistent with existing economic philosophy, as evidenced in Robert Nathan's scholarly presentation on the subject (231/40,200-209). It will be the rule here.

b. Canadian Taxes

El Paso charges that all NNEB analyses have failed to account for the 15% Canadian withholding tax on dividends. It is El Paso's position that, in order to make equity investment in Canadian Arctic equally attractive with investment in Alaskan Arctic, Canadian Arctic must allow an effective rate of return of 15%. Considering the 15% Canadian withholding tax on dividends,

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1/ While environmental impact and net national economic benefit are each factors to be weighed in reaching a final determination here, environmental impact cannot be quantified into dollars and, hence, should technically be excluded from an NNEB study. In this connection, Staff observes that the purpose of the National Environmental Policy Act is to help minimize the social cost associated with any project affecting the environment.

2/ Arctic Gas admits that these expenses would aggregate to something less than the amount of U.S. income taxes paid.

the gross rate of return demanded by U.S. equity investors will be something above 15%. The incremental unit costs to U.S. shippers which this increased return (and related taxes) will produce are classified by El Paso as costs for NNEB purposes. El Paso is justified in this regard, although not to the extent which it apparently believes, because it must be remembered that the effective Canadian tax rate is below the combined U.S. and Alaska rate by some 5%.

Schedule 4 of Arctic Gas' Exhibit AA-127 indicates that Arctic Gas pays no Canadian government corporate income taxes, moreover, until 3½ years after the project is in operation. Accordingly, Arctic Gas does not view such tax liability as a cost until 3½ years have passed, despite the fact that, with the commencement of service, it would begin collecting through its rates an amount attributable to Canadian income taxes. El Paso considers this a discriminatory tactic by Arctic Gas and urges that such tax deferral should not be permitted to mask the fact that, insofar as the U.S. consumer is concerned, the Canadian tax, like U.S. income taxes, should be viewed as a cost from the time it is absorbed by the ratepayer.

El Paso here fails to notice two things. First, under accepted tax normalization practices, deferred taxes are offset by a reduction to rate base, the effect of which is to neutralize the loss in time value of money which the ratepayer would otherwise experience. Second, El Paso overlooks the fact that Arctic Gas, in Exhibit AA-127, actually discounted all taxes on a cash basis and assumed tax deferral for both Arctic Gas and El Paso. Based on the foregoing, it would be improper to assign to Arctic Gas any additional cost related to deferral of Canadian income taxes.

A further El Paso oversight involves El Paso's failure to account for the one-sixth flowback of Canadian taxes to the U.S. in the form of U.S. taxes. The phenomenon is plausibly described at page 117 of the DOI NNEB study (Exhibit EP-231) and is reflected in the calculi used by Staff and Arctic Gas. In its NNEB Reply Brief, Arctic Gas estimates that this one-sixth reduction in the tax costs ascribed to Arctic Gas by El Paso would increase Arctic Gas NNEB by $0.1 billion (Brief, pp. 15-16).

C. Conclusions

The costs and benefits associated with each of these projects measure in the billions of dollars. These numbers alone clearly place these projects on a grandiose scale when compared with what has gone before in the natural gas industry. But to argue that the costs and benefits of such projects standing alone can have a measureable (positive or negative) long-term impact on an economy whose annual GNP measures in the trillions borders on the fanciful. Comparisons of the small difference in impact of the $2 to $3 billion in any year are totally impossible, given existing tools.

Alcan, in its initial NNEB brief, is correct in pointing out that, while sophisticated cost/benefit analyses have been used in assessing some proposed defense projects with perhaps questionable results, never has there been an NNEB study to its knowledge which involves private projects or ones as ambitious as the ones contemplated here (206/35,332; 35,383; 35,416; 148/24,149-150). Moreover, due to the relatively recent acceptance of these studies and the length of time over which costs and benefits must be projected, it is too early to gauge the accuracy of those analyses which have had an influence on past decisionmaking. 1/ NNEB studies, as tools for predicting behavior into the future, are still at an embryonic stage of development.

The DOI model developed and used here is essentially a cost/benefit model pegged to the U.S. economy for a 20-year period beginning several years from now. It incorporates several variables which are beyond the control of science or diplomacy. Hence, great care must be taken in drawing any conclusions from the results obtained through applications of such a model. No party contends, nor can it be found, moreover, that the DOI model is necessarily the one best-suited to the task at hand. It is, however, the only one developed on the record, and it is accepted by all parties as sufficient for the purpose of demonstrating that each of these projects will provide some net national economic benefit. As evidenced above, any comparative analysis must proceed cautiously, bypassing as many variables as possible. To have any reliance, the modeling must be subject to reproduction and testing. Neither can be done here. On the strength of the evidence, as discussed above, it is found that the Arctic Gas project, with a western leg, stands to generate a greater net national economic benefit for this country than either the El Paso or Alcan projects. The selection of Arctic Gas as the project most likely to maximize NNEB is predicated, in the final analysis, on a few, clearly justified assumptions. But even these assumptions, of course, cannot be considered inviolate. In light of the foregoing, it

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1/ It is noted also that NNEB studies were relied upon as justification for the existing form of the U.S. Postal Service.

would be clearly inadvisable to attach more than a modicum of weight to findings based upon these NNEB analyses. In sum, while the studies are of more than purely academic importance, given the state of the art, it can be fairly stated that rearrangement of these projects on the NNEB ladder would in no way affect the ultimate decision below.

Table II-3-1
From Ex. ST-54, See p. 322 supra
Net National Benefits
With BTU Adjustment
(Billions of Dollars)

Discount Rate - 10% to January 1, 1977
Lower 48 Transport Costs - 2¢/Mcf/100 miles

	$12 per barrel oil		$8 per barrel oil	
Non-Alaskan Supply	High	Low	High	Low
Alaska-Canada 1/, 2/				
With Western Leg	6.382 5.555	9.444 8.617	2.589 1.762	5.651 4.824
w/o Western Leg	6.707 5.903	9.705 8.901	2.914 2.110	5.912 5.108
Improved El Paso 1/	6.257	9.103	2.473	5.319
Fairbanks-Alcan 1/	6.769	9.800	2.936	5.966
Northwest 3/				
With Western Leg	4.464	6.904	1.603	4.043

1/ Based upon an Alaskan Supply of 2.5 BCFD from mid-1982 through 1985, 3.5 BCFD from 1986 through 2001.

2/ Higher figure based upon a Mackenzie Delta flow of .5 BCFD from mid-1982 through 1985, .9 BCFD from 1986 through 2001. Lower figure based upon system constructed for above Mackenzie Delta flow which does not materialize.

3/ Based upon an Alaskan supply of 2.4 BCFD for 20 years.

XIII

ECONOMICS

The Natural Gas Act requires that the Commission determine that a project be found to be consistent with the present and future public convenience and necessity to warrant a grant of a certificate. Construction and operating costs, including financing, determine for a regulated utility the cost of transportation to the consumer and represent therefore an essential ingredient in determining where the public convenience and necessity lies. 1/ This section analyzes costs, but as shown below, limited almost entirely to those costs put into the record by the respective applicants.

The applicants each filed initial, reply and rebuttal Economics Briefs. These briefs, to a large extent, augment the applicants' Construction Briefs. Other parties essentially responded to these briefs in their Position Briefs (Staff pp. 18 et seq.) or Wrap-up Briefs.

A. Methodology and Assumptions

Due to the long lead time that was known to exist between the beginning of the hearing process and the beginning of the flow of gas, it was determined that the only fair method of comparison between the competing applicants was to fix a date for computation of costs. The date of July 1, 1975, was not arbitrarily fixed but represented the parties' best analysis of a date close to the date the hearing commenced, which, hopefully, would not be too remote from the date of decision. Choosing any date for purposes of comparison, however, must be understood as being what appeared at the time to be the best solution to a difficult problem.

Thus no attempt was made to escalate the mid-1975 costs to the year of construction or operation by explicit use of any general inflation index. 2/ Moreover, no effort was made to try

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1/ Congress clearly has expressed the same general standard in the 1976 Alaska Natural Gas Transportation Act wherein it indicated the need for a broad range of economic cost comparisons.

2/ The costs before the Canadian National Energy Board are escalated costs. While that procedure also admits to comparison, it too is fraught with a large number of assumptions which can easily cause misleading comparisons.

to determine whether the sum of the inflation of individual components of these projects would or would not exceed general averages of inflation. By way of example, assume that a tanker bulkhead and a compressor station soundproof door both cost $500 on July 1, 1975. There is simply no way to know the cost of the bulkhead installed on February 1, 1980, compared to the cost of the door installed on May 1, 1981. 1/ In the comparisons made at this time in this proceeding, it is implicitly assumed that all components of each project inflate at the same level and that the same rate of inflation occurs when projects are compared to each other. By the time any of these projects is built, however, inflation will have made the costs rise significantly beyond mid-1975 estimates and may have made costs rise faster for some of the component parts than the general average increase. It cannot be overemphasized, therefore, that the primary credible use to be made of the cost estimates in this record is for comparison of the three projects on the basis of July 1, 1975 dollars.

Several additional simplifying assumptions are made at the outset:

(1) The term "economic issues" is used here to mean those issues which directly affect the unit delivered cost of gas under the several projects expressed in terms of dollars per Mcf or MMBtu.

(2) Given the findings in the Gas Supply section, the analysis is primarily of those proposals to transport initial volumes in the order of 2.0-2.5 Bcf per day from Alaska.

(3) The unit costs to be compared are those for the overall projects rather than the costs to the various market areas. The problem of what volumes will be delivered in the discrete market areas is common to the three cases and will, assumedly, be decided the same whichever project is authorized.

Another threshold issue is the proper time frame for making cost comparisons. This issue takes on significance because each of the applicants assumes a 2-year build-up period in project

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1/ Various models used by the parties, such as El Paso's Fluor model, do make differential analysis of costs (e.g. 68/10,522). The projections forward, however, reflect only a general average, even though Fluor could probably furnish more accurate projections. The model Fluor used is explained in the record. It is considered proprietary.

volumes. The volumes to be marketed build up to the 2.25-2.4 Bcfd level over 2 years. With total costs being the greatest in the first 2 years and volumes the lowest, the unit costs would be very high. Alcan proposes to recover these costs as incurred. Both Artic Gas and El Paso propose normalizing techniques under which certain of these costs would not be recovered as incurred but would be deferred and recovered in later years. Arctic Gas believes average costs for a seven year period are the fairest to compare "because in a seven-year average, the effect of the failure to defer buildup year costs is approximately zero." 1/

What surely must rank as one of the most curious arguments in this case is Alcan's insistence, primarily on this issue, that all cost comparisons be made without reducing disparate parts to common denominators. Possibly there is an undisclosed Aristotelian philosophy which eschews reducing discrete parts to some single form for comparison. But until it is discovered, it does seem logical that, in comparing different projects, benefits and costs should be measured, to the extent possible, on a common basis. Alcan, of course, does not shun comparisons; it wants them only on its own standard and is in reality arguing primarily that Arctic Gas' comparing Alcan's assumed early phased completion to Arctic Gas' later gas deliveries is unfair.

Despite Alcan's objection that project-life costs are the best costs to be analyzed, 2/ Arctic Gas is correct in its argument that the effect of these different approaches cannot be allowed to mask the evaluation of the economics of the several projects. If a so-called phasing of initial rates makes sense, it would be required for whichever project is authorized, and no comparisons, such as those by Alcan, where costs actually to be incurred by customers in the first 2 years are ignored, are acceptable. The Arctic Gas approach will be used for comparisons to the extent possible.

B. General

An analysis of the economic considerations and comparisons requires findings as to the probable construction costs. As will be seen below, Arctic Gas' construction costs as amended by it to add almost one-third billion additional dollars is the probable base cost for Arctic Gas. El Paso's costs are increased to include a ninth LNG ship and seventh LNG process train to reflect the minimum necessary reliability for its system. These aggregate almost $400 million. Alcan's plan has been found not capable of

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1/ Arctic Reply on Economic Considerations p. 60.

2/ Alcan Rebuttal on Economic Matters pp. 8-12.

being constructed as proposed, but its costs as it shows them are used, nonetheless, solely for comparison purposes. None of the studies immediately below include inflation pressures on the 1975 data or construction overruns other than described in this paragraph.

1. Arctic Gas

To restate, as far as costs are concerned, Arctic Gas' general position is that a reasonable comparison of its costs and those proposed by its competitors shows that it is substantially cheaper. But giving its detractors the benefit of every benefit and penalizing Arctic Gas in the way they propose, Arctic Gas argues it is still within pennies of El Paso's best unit cost of service. 1/ Even on El Paso's own terms, Arctic Gas argues that El Paso cannot show its superiority. With any adjustments favorable to Arctic Gas, Arctic Gas is clearly superior. From the economic point of view here--comparison of 1975 dollar cost per MMBtu--if Arctic Gas construction timing is even minimally credible, it is clearly superior to either El Paso or Alcan.

El Paso, Alcan, the State of Alaska and the Conservation Intervenors refuse to accept Arctic Gas' construction timing as credible. Throughout the proceeding, El Paso has attempted to overturn the delivered cost advantage held by Arctic Gas' conventional pipeline proposal by attacking its construction timing--all to the purpose that the decisional process would then turn more on non-economic elements where El Paso conceives of itself as having the edge. The absolutely necessary linchpin of this attack is an additional Arctic Gas construction year whereby astronomical sums for interest charges are added to the Arctic Gas' construction costs and the gap between Arctic Gas and El Paso narrows.

But to recapitulate, El Paso's analysis is not credible. While El Paso's criticism, in fact, may have motivated Arctic Gas to augment the cost and size of its crews and equipment to meet the criticisms, once augmented, the original premises about the need for the additional year's construction drop out of the case. The so-called "risk analysis," based primarily upon the erroneous additional winter construction season, limitation on camp moves, and fewer workers and

1/ The Arctic Gas project is predicated upon the common transportation of gas destined for Canadian and United States markets. Arctic Gas allocates costs for these two movements on an Mcf-mile basis. See Canadian Issues and Cost Allocation discussions, *supra*.

spreads, goes with it. 1/ Thus, the so-called "hard" figures of costly delays as originally pressed by El Paso become meaningless even if originally valid. All that remains is a more than healthy skepticism as to whether Arctic Gas can perform within its original estimates. To meet its schedule and avoid the El Paso criticism, it would put up even more construction spreads in the second and third construction seasons. These costs, which can be substantial, are nonetheless cheaper than lost time because they come through at the end of financing and will not involve costs as large as the interest charges on an additional year's construction.

2. El Paso

Contrary to El Paso's position, El Paso's costs are subject to adjustments which are not negligible. El Paso's ability to transport LNG under its low-volume case between its LNG terminals with eight ships, on the schedule El Paso maintains is workable, calls for many, many years of almost flawless operation requiring that virtually every ship movement and every ship loading occurs at the optimum performance level with parade-ground precision. 2/ If in fact the volume is less than 2.4 Bcfd so that there is a margin of additional capacity on the shipping, the cost per Mcf rises substantially. Nor can projected fuel efficiency rates at the liquefaction plant be accepted as fact. Despite Fluor Engineering Company's brilliant presentation of its designs, there are assumptions about the ultimate efficiency of the LNG plant which may not prove valid because of (1) the probable need for a different plant cooling system and (2) a likelihood either that the gas at the plant inlet will not be as rich as that leaving Prudhoe Bay or that the LNG plant will be used for liquid extraction. See supra, Construction. Key to El Paso's lowered cost estimates is that the efficiency of the redesign of this plant be achieved and that it too then operate at maximum efficiency for its life.

In sum, a ninth ship and a seventh LNG train are needed by El Paso. While plant efficiency may be reduced or other construction costs exceeded, they are not considered. Adjustment is made for financing.

1/ On brief, as is discussed supra, in the Construction section, El Paso repackaged the risk analysis as primarily an exercise in logistics. It is still the same risk analysis.

2/ In fact, the discussion in the Construction section on cryogenic ships, supra, finds that even under optimum conditions making all assumptions favorable to El Paso, El Paso could just squeak through to lift the anticipated volumes under the low-volume case if a full 2.4 Bcfd were processed.

3. Alcan

Alcan has a smaller-capacity pipe which cannot be efficiently expanded to carry greater volumes anticipated from the North Slope. 1/ Its pipeline is clearly undersized, with no cheap expansibility. One of its great benefits, it argues, it that its smaller line utilizing excess capacity of existing Canadian pipelines can be in place more quickly than either of its competitors. Whatever is the "excess" capacity of the Canadian pipelines, of course, has not been proven on this record. Assuming that Alcan's line is properly sized and that it can be built as suggested using excess Canadian pipeline capacity, it has had to conduct a razor-edge balancing act on future gas volumes from both the U.S. and Canada. Too much or too little scuttles its proposals, for if either gas supply is more than it projects, Alcan's timing will not work. Its Canadian sponsors have had to maintain a similar balancing act with regard to timing of the decisions of both the U.S. and Canadian regulatory bodies to permit construction of both Alcan and Maple Leaf. See also Finance section infra. What is clear is that there is not the slightest chance that the schedule Alcan originally proposed and the benefits it perceives from that timing will be met.

As to Alcan's plan to phase-in gas, the unrefuted evidence of the producers as to the earliest time North Slope gas would be available for sale and the volumes to be available is directly contrary to an essential element of its plan. 2/ Thus, again there is no basis for Alcan's early construction schedule, either in the timing of regulatory approvals or the availability of gas conditioning facilities permitting early phase-in sales of Alaskan gas.

1/ Alcan, of course, will build anything. It states in several of its briefs that if a 48" express line is desired to pick up larger initial volumes or to avoid use of low pressure looping of Canadian lines, it will build it. It is not clear what this proposal would do to Maple Leaf.

2/ An Alcan witness testified in the abstract that a gas conditioning plant could be built to process 1.75 Bcfd in 3½ to 4 years if a large number of contingencies fell into place (252(2)/44,100). Producers have estimated that the plant would require 4 to 6 years to design, fabricate, and construct and that the plant would not be available until 4½ to 5 years from commencement of oil production, now scheduled for mid-1977 (ALA-33).

Construction is another matter. Assuming that Alcan could demonstrate that it would be permitted to build on the Alyeska right-of-way, it could not say how close to Alyeska's line it would be permitted to come, and construction costs--when a line cannot be specifically placed--begin to be vague. Not that its costs elsewhere can be accepted with confidence. Its engineers are excellent; Westcoast's in particular displayed a great knowledge of their art. But, given the time constraints and magnitude of the job to be done and the vagueness of much of the specific alignment at the time their estimates were made, they were not able to support costs in more than a general way in either the U.S. or Canada. 1/ Blind faith in its engineers' expertise cannot replace the ability to independently check figures against known plans of pipeline construction on fixed rights-of-way.

Despite the conclusions reached that Alcan's plan cannot be built during the time frame proposed and that its line cannot properly be analyzed for costs, either environmental or monetary, the sections below nevertheless set forth Alcan's project assuming Alcan's costs as proposed by it.

1/ The Alcan alignment, as presently proposed, would impact the proposed Kluane National Park and Game Sanctuary in the Yukon, the proposed Pickhandle Lake IPB Ecological Reserve in the Yukon, waterfowl habitats at Pickhandle, Kluane and Teslin Lakes, and the Liard River Hotsprings Provincial Park and Nordquist Lake, a grazing ground for elk, in British Columbia (ST-52). Since the alignment is still susceptible to voluntary alterations or those imposed on environmental grounds, it is impossible to accurately determine the costs of the Alcan project on the Canadian side. Moreover, the Foothills segment in the Yukon crosses into the area of the Shakwak Fault, a possible extension of the Denali Fault. The exact alignment of the line and activity of the fault are either unknown or in dispute. Again, cost estimates are subject to change here.

C. Cost Comparisons

The decisional process described here is based on the starting point of each applicant's view of its own costs and then an analysis of the short-comings of each case as advanced by the adversaries. With these assumptions in mind, an analysis of each of the plans is set forth below.

1. Arctic Gas

Arctic Gas shows its costs per MMBtu rounded here to the nearest cent) to be as follows: 1/

Year 1	$ 1.46
Year 2	1.48
Year 3	1.45
Year 4	1.42
Year 5	1.38
Year 6	1.34
Year 7	1.30
5-Year Average	1.44
7-Year Average	1.41

The scope of the dispute between Arctic Gas and El Paso is evident from El Paso's adjustments. El Paso adjusts Arctic Gas' costs to reflect what El Paso argues are appropriate overruns (Reply Economics Br. 90-91) as follows (in billions of dollars):

	Per Arctic Gas	Per El Paso	Percentage Increase 2/
Variable			
Other Than AFUDC	$ 0.59	$ 1.39	$ 138%
AFUDC	1.30	3.07	135%
Subtotal	1.89	4.46	136%
Fixed	4.19	4.27	2%
Total	$ 6.08	$ 8.73	44%

An analysis of El Paso's estimates shows that the estimates of fixed costs do not represent the significant difference. These fixed costs include all costs south of the 60th Parallel, where El Paso merely adopted Arctic Gas' costs, as well as most costs to the north where Arctic Gas' costs also were used--land, construction materials and most ancillary facilities. Some ancillary facilities as well as the crossing by the Prudhoe Bay

1/ Exh. AA-140, Sh. 1.

2/ Based on unrounded data.

Lateral of the Mackenzie Delta river crossings were re-estimated on a lump-sum basis. But, as said, this is not where the main dispute lies; these increases are only 2%, albeit $ 80 million.

It is in the variable costs where El Paso argues the increases mount. El Paso's increase of the estimated variable costs --other than allowance for funds used during construction-- is ten times as great on a dollar basis as the increase in fixed costs and 2.38 times what Arctic estimates. These variable costs are those related to installing the pipeline, air support and camp installation. As noted, these increased costs flow from Green's criticisms of trenching, blasting and welding and how much more personnel would be needed to do the jobs, and what it would take to house them and move them around. But, as Alcan noted, Arctic Gas conceded the desirability of providing more resources, such as, for example, $120 million more for two more spreads for Winter 3. The point of its construction concessions is completion without a time overrun into an additional year. It also provided an additional $210 million for contingencies, for a total added amount of $330 million.

The lion's share of the increase, $1.77 billion out of a total of $2.65 billion, is allowance for funds used during construction which El Paso computes to be 2.35 times what Arctic Gas shows. This cost arises solely from the construction delays which El Paso insists will occur. However, as has already been held, Arctic Gas can construct its line in three winters at some additional cost. Accordingly, although Arctic Gas' $6.08 billion estimate may be understated, the understatement is not likely to be anywhere near the full $470 million increment from $330 million to El Paso's asserted $800 million. These costs however, even if incurred, do not carry with them the high-interest charges of an additional year's construction time which would be applicable to all monies already drawn down.

Another issue must be examined here. Arctic Gas shows a unit cost of $1.39 for its fifth year of operating a line transporting 2.25 Bcfd of gas from Prudhoe Bay to the U.S. market. 1/ This cost, however, reflects transporting an equal volume of gas from the Mackenzie Delta to the Canadian market. 2/ It has been found that 1.0-1.5 Bcfd rather than 2.25 Bcfd is the volume to be expected from the Mackenzie Delta. Because the Canadian Arctic segment of the project hauls gas to both markets, a lesser volume of Canadian gas would impose higher costs on the United

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1/ Exh. AA-141, Sh. 1. (A one-cent difference from Exh. AA-140, Sh. 1.)

2/ Exh. AA-143, Sh. 5.

States gas. Thus, the cost of service would rise from $1.39 to $1.54 if 1.5 Bcfd of Canadian gas were transported and to $1.66 with only 1.0 Bcfd. 1/

2. El Paso

El Paso shows its costs per MMBtu (rounded here to the nearest cent) to be as follows: 2/

Year 1	$ 1.96 3/
Year 2	1.91
Year 3	1.88
Year 4	1.84
Year 5	1.80
Arithmetic Average	1.88

El Paso calculates the effect of Arctic Gas' proposed financing adjustments to be $ 0.16. 1/ As already noted, Arctic Gas' arguments on comparability for financing, as well as phasing, are sound. The El Paso costs will be adjusted accordingly. Additionally, it has been found that reliability of the El Paso project requires a seventh liquefaction train and a ninth LNG ship. The additional capital costs would be $179 million 5/ and $203 million, 6/ respectively. The incremental cost of service for the first year of service would be $95 million or $0.11 per MMBtu. 7/

1/ These calculations reflect the mileage ratios implicit in Exh. AA-143, Sh. 5 adjusted from 2.25 Bcfd to 1.5 and 1.0 Bcfd and such revised costs substituted in Sheet 3.

2/ Exh. EP-265, Sch. 22.

3/ These amounts include the cost of shrinkage. The first-year cost, excluding shrinkage, is $1.836. See below.

4/ El Paso Brief on Economics p. 64.

5/ The incremental cost of one train is from Exhibit EP-178 data less Exhibit EP-207 data.

6/ The incremental cost of one ship is from Exhibit EP-185 data less Exhibit EP-212 data.

7/ The sum of the incremental costs for one train and one ship from Exhibit EP-191 data less Exhibit 228 data divided by 887,662,000 MMBtu.

The effect of the several adjustments is to indicate a 5-year average cost for El Paso as follows:

Per El Paso	$ 1.88
Additional Financing Charge	0.16
Additional Ship and Train	0.11
	2.15

It should be noted that El Paso's costs are unavoidably high. They show a national average cost in the first year exclusive of shrinkage of $1.836. Of this amount, $1.675, over 90%, is the cost of the regasified product at the outlet of the Western LNG Terminal. Not only does this represent a cost before any transportation occurs in the contiguous United States, it also excludes so-called shrinkage, meaning fuel, all the way from the inlet of the El Paso Alaska gas pipeline through the regas terminal.

One last caveat is in order. As recognized in the Construction section, El Paso in all likelihood would revise its plans so as to avoid the additional trains or ships. The costs therefore may decrease, dependent upon the credibility of the revisions.

3. Alcan

Alcan shows its costs per MMBtu for the first five years of full operation to be as follows: 1/

Year 1	$ 1.71
Year 2	1.66
Year 3	1.62
Year 4	1.56
Year 5	1.50
5-Year Average	1.61

Relying on Alcan's own witness, El Paso disparages Alcan's costs as at best an "educated guess." 2/ Arctic Gas characterizes Alcan's project as "embryonic"; 3/ nevertheless, it recomputes

1/ Alcan Initial Brief on Economics App. A.

2/ El Paso Reply Brief on Economics p. 112.

3/ Arctic Gas Reply Brief on Economics p. 50.

costs as it did for El Paso to make financing comparable but, in addition, to inject the first two years of partial operation. Arctic Gas' view of Alcan's costs (rounded here to the nearest cent) is as follows: 1/

Year 1	$ 2.84
Year 2	2.18
Year 3	1.73
Year 4	1.69
Year 5	1.63
Year 6	1.59
Year 7	1.53
5-Year Average	1.91
7-Year Average	1.80

It can be noted that Alcan's estimated costs for the comparable years (Alcan's 1-5 and Arctic Gas' 3-7) differ by only one-three cents. What is significant is revealing the costs for the two years of partial operation. As already stated, since the costs have to be paid, their existence cannot be hidden or ignored. In conclusion, Alcan's average cost for the first five-to-seven years of operation is about $1.85.

4. Summary

In summary, the costs (or better, the flavor of the costs) are as follows:

Arctic Gas	$ 1.60 2/	(a fifth-year figure)
El Paso	2.15	(a five-year average, adjusted)
Alcan	1.91	(a five-year average)

Arctic Gas is superior under this comparison. It is so found.

D. Cost Projections by Markets

Another assumption accepted in this section is that unit costs for the three projects may properly be compared on the basis of average nationwide costs. The allocation of costs to specific markets, absent producer sales contracts and specific

1/ Exh. AA-140 Sh. 1.

2/ Average of $1.54 and $1.66, supra.

volumes, was a problem common to all three projects, and changes in the underlying assumptions would presumably impact on each project equally regardless of which project was authorized. Specific costs, including distribution costs, cannot be made on a nationwide basis at this time from this record. The Alaska Natural Gas Transportation Act of 1976 directs that estimates of costs for discrete parts of the country for the authorized project for each of 20 years be discussed. Even if the construction, financing and operating costs are exactly as submitted by the successful applicant, as already shown, if this 20-year analysis cannot be done on the present record for nationwide costs, it cannot be done for regional costs. Although costs are presented for some pipelines for some regions, no detail is presented with respect to a state or part of a state other than some six or seven metropolitan areas in a few states. Again, while costs are presented for some years, the detail is lacking for 20 years.

There is an additional problem. Efforts were made to put in place the computer software used by the parties so that their submitted materials could be verified and so that changes in their construction timing or costs, financing presentations, and rates of return could be made to reflect alternative assumptions which would affect a comparison of costs. See the full discussion in the Potpourri section infra. This was unsuccessful, for the most part. The Commission, or at least the Presiding Judge, at this time does not have in place the ability to make meaningful and expeditious analyses of what occurs when the applicants' construction or financing assumpations are varied. The magnitude of the problem in attempting to make varied assumptions without the appropriate tools is highlighted by even passing reference to AFUDC. An example is the change in the cost of financing as shown by El Paso's adjustment of an estimated 1.77 billion dollars of AFUDC assessed against Arctic Gas, but the only way that these increased costs can be computed is on the basis of complicated drawdowns of funds over a many-year period. Changes in timing of the need for construction funds and time of drawdown can have huge effects upon total costs, and the ramifications of these changes cannot be computed by hand. This record as it now stands, as well as the lack of tools, does not give this decision-maker the ability to make comparisons other than with the 1975 costs and on the basis of those limited studies provided by the parties.

XIV

FINANCING AND TARIFFS

The ability to finance the billions of dollars necessary to build any of these proposals in the traditional money markets under traditional tariffs has been at issue from the beginning. As a general overview, the basic issues have evolved into the following questions:

(1) Should recovery of the transportation system expenses, debt capital and cost thereof be guaranteed in all events?

(2) Should recovery of transportation system equity capital be guaranteed in all events?

(3) Who should provide such guarantees and upon what terms?

(4) What rate of return on transportation system equity should be allowed?

(5) Should FPC-regulated shippers be allowed, through operation of special provisions in their individual tariffs, to automatically flow through to their customers all charges incurred by the transportation system?

(6) Should shippers bill their customers for Alaskan gas on an incremental basis, or should the charges be "rolled in" with the costs of their other gas supplies?

(7) Should FPC-regulated shippers be permitted, during the construction period, to include in their individual costs and rates amounts reflecting the financing costs for their equity participation in the transportation system?

(8) Is additional federal and/or state legislation needed to insure recovery of costs from ultimate consumers?

Additional questions or suggestions addressing financeability have been raised on the record by various parties which are either subsumed in the discussion herein or considered so remote, impractical, or unmerited as to warrant no discussion. 1/

The applicants and the prospective shippers, supported by their policy and financial witnesses and generally by the Department of the Treasury, 2/ look first, if not exclusively, to the ultimate consumers of Alaskan gas for the necessary guarantees to insure the financeability of the transportation system. It is their general view that financeability depends upon assurance that investment and carrying costs thereon (at least for debt capital), as well as all operating costs, be recovered from consumers whether the system is aborted prior to operations or suffers a prolonged service interruption or premature abandonment after operations have commenced. 3/

1/ E.g., suggestions that pricing of the entire Alaskan gas flow from wellhead to burner tip be deregulated or that a substantial portion of the Alaskan gas be reserved for industrial markets.

2/ The participation of the Department of Treasury through its Office of Deputy Assistant Secretary for Investments and Energy Policy has been invaluable to a fuller understanding of these issues. Deputy Assistant Secretary John Niehuss, Mr. Theodore Barnhill, and their staff went far beyond mere cooperation, and their impressive presentation on the record and briefs will enable the Commission to resolve these matters more effectively.

3/ There appear to be different views on assuring recovery of equity capital in all events. Arctic Gas and Alcan seem to take the position that only debt service needs such protection. (See, e.g., Arctic Gas Brief Relative to Financing Brief, p. 3; Alcan Initial Tariff Brief, pp. 30-31.) El Paso, on the other hand, believes equity capital will also need protection (El Paso Brief on Financing and Regulatory Action, p. 3). The prospective shippers supporting Arctic Gas want their equity investments protected, at least if the Arctic Gas Project is not completed (Arctic Gas Rp. Br. Rel. to Arctic Gas and El Paso Tariffs, p. 19). Treasury does not support protection of equity capital (Brief, p. 4). Staff opposes such protection but takes no exception to the continued collection of depreciation charges under the cost-of-service tariff in all events, which could operate to return equity investment.

Implementing the form and the timing of the various guarantees depends on the commencement of proposed operations. Once service commences, the tariff of the transportation system will become effective and will determine what costs and charges are assessable against the shippers and, through them, ultimately against the consumers. 1/ Each of the applicants proposes the use of a so-called "all events" cost-of-service tariff. 2/ Their tariffs are sufficiently similar to permit a general discussion which is applicable to each.

In order to understand the magnitude of the shifts of financial burdens if cost-of-service all-events tariffs are adopted, the following description details the mechanism of billing under the tariff. Under the proposed all-events tariff, shippers would enter into service agreements, presumably having a term of 20 years, which would bind them to pay monthly their allocated share of the total dollar cost of service of the transportation system, including operating costs, all taxes, depreciation charges, and a composite weighted rate-of-return on rate base 3/ reflecting the actual capital structure, the actual cost

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1/ No one except Alcan appears to argue that tariff billings can or should begin prior to gas deliveries.

2/ Recognition must be given to the substantial and excellent contribution of staff tariff expert Mr. Raymond A. Beirne in focusing attention on various tariff problems and thus assisting the parties to compromise many of the detailed tariff issues. References herein to applicants' tariff proposals reflect the revised *pro forma* tariffs submitted after the close of the hearing.

3/ The rate base would consist essentially of net plant in service (original cost less reserves) plus working capital. Cost of plant would include a carrying cost over the construction period, i.e., an allowance for funds used during construction, commonly referred to as AFUDC.

of senior securities, and an allowance on equity. The after-tax equity return sought ranges from 15% to 17%. Return on equity and related income taxes are reduced pro rata if the transporter is unable to accommodate at least 80% of the volumes tendered by a shipper within the contract entitlement in any month. 1/ No other reduction in charges is contemplated by the tariff. Thus, during periods of prolonged service interruption or if the system is abandoned prematurely, all costs would continue to be billed to shippers over the life of the service agreements. Since the depreciation charge would continue to be collected, it would appear that sufficient revenues would be generated not only to retire the debt but also to recover equity capital. 2/ If no other provisions but these were in place, debt recovery would be guaranteed by the consumer once the system was operational.

In addition to the all-events tariff, various rate-making mechanisms and techniques have been suggested to generate revenue to protect debt service in the event of noncompletion (i.e., nonoperation of the tariff) and assist shippers in financing their equity investments. These will be discussed infra.

1/ Under the Arctic Gas and Alcan tariffs (but not the El Paso Alaska tariff), willful refusal to perform agreed-upon service results in abatement of full cost of service for the affected shipper.

2/ In all likelihood, however, lenders would insist on an accelerated repayment of the debt in the case of abandonment. This would bar equity recovery until that repayment had been accomplished, thus severely impairing the equity value.

Assuming that the risks will be shifted to the consumer and that the Commission puts in place all of the rate innovations proposed by applicants, the question becomes whether the prospective pipeline shippers and the financial community would still require additional legislative guarantees to insure the permanence of the regulatory actions. El Paso thinks that private financing will work with only regulatory guarantees; Arctic Gas, Alcan and most of the pipeline transmission companies think not. Treasury, by arguing that additional regulatory legislation is easier to get from Congress than federal financial guarantees would be, clearly supports the El Paso position.

The second area of disagreement is the individual financial plans. Each applicant has presented a detailed financing plan tailored to its own proposal on the one hand, but on the other, including some methodology which would be applicable to any project of this magnitude seeking funds from the capital markets. As elsewhere in this proceeding, several aspects of the financial plans press to the very edge of what has been accomplished by past utility financing, and the applicants are often at odds with each other over projections of what in fact will be required. El Paso in particular attacks both the Arctic Gas and Alcan plans because they rely on what El Paso believes are inadequate capital supply markets for substantial portions of their funds. They in turn attack El Paso for including in its plan financial schemes which the financial community assuredly will reject.

Briefs were filed by the applicants, Staff and Treasury. 1/ Numerous pipeline shippers and a number of states, including California, New York and Wisconsin, also addressed these issues in various briefs.

A. Marketability

Any rational analysis of financing cannot begin without discussing that ingredient of all business endeavors which warms the heart of those who invest for profit--there must be a willing buyer for the product. Unlike most other past pipeline certificate cases where large residential, commercial and industrial markets could be assumed, here we have a constantly shrinking industrial load which will have cost consequences because lower-priority supply shortages will cause a significant shift in

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1/ Treasury's brief was not filed until late December under an arrangement whereby Treasury was given leave to respond to the Financial Briefs of applicants.

load factor consideration. 1/ The higher priority market remaining could well prove sensitive to price, and the unspoken message from the financial community is that the time has come to assess the risk of non-saleability. 2/ It is now apparent that the financial community has raised a warning flag; to ignore this sub silentio questioning would be foolhardy. Although the financial testimony is in the language of the Street, the bottom line is that the lender is not sure he could take over a failing project, wipe out the front money, and recoup the loan by selling a product to consumers at the high prices that might occur.

One of the prime reasons for these high projected prices for delivered gas, of course, is evident from the makeup of the project. Rather than the usual business compromises arranged both to make a marketable product and to split the benefits among those who will gain the financial advantages from a successful venture, all of the prospective beneficiaries are looking for the top dollar. The producers and State of Alaska want a high wellhead gas price even though (1) their overall profit from their North Slope investment is already assured by the sale of the Prudhoe Bay oil under FEA regulations, (2) the product is at the end of an expensive transportation system, and (3) the market is no longer assured. Governor Jay S. Hammond of Alaska, for example, sought and will probably seek again Alaskan legislative approval to raise the severance tax on hydrocarbons from 4% to 10%. Access without equity contribution, 3/ withdrawal, underlifting and a host of other proposals put Alaska in the forefront of seeking special treatment at the consumer's expense. As discussed in the rate-of-return section, the pipeline shippers want consumer guarantees to repay their equity investment but still seek 15% to 17% after tax return in what could be a low-risk situation. The financial community in general also wants a high rate of return regardless of how the risk might be reduced by consumer or taxpayer guarantees. In the common vernacular, "everyone has his hand out." It is in large measure the combination of these elements which creates the serious questions of marketability and, in turn, financeability. Only a limitation on the field price of gas to

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1/ As the sales load factor declines, the unit cost of meeting seasonally high residential and commercial demands increases.

2/ See also filings by the State of New York.

3/ These terms are discussed supra, and also see Legislative Proposals in Potpourri section, infra.

reflect its value and a reduction on investment returns to reflect limitations on risk can bring these projects "in from the cold." See infra.

The state of this record, furthermore, permits findings of marketability based only upon general assumptions rather than contracts of sale with fixed volumes, at known prices, to given markets. But marketability from a regulatory and financial point of view, *inter alia*, must be a fact based upon a price, a volume, and a specific market--a willing seller and a willing buyer being first, not last, in the equation. (See infra.) Only when sales contracts are in place can the Commission give its imprimatur to findings on marketability. Thus, marketability must be viewed anew as a part of the overall presentation of producer sales contracts and financing at the next phase of these proceedings.

There is an additional factor, however: regardless of how one may view efforts toward energy independence, the fact remains that it is necessary to secure expeditiously the greatest amount of additional indigenous energy supply that can be attached economically. Although the delivered price of Alaskan gas may be high, it need not be so high as to be uneconomic. The nation is currently embarking on a multibillion-dollar oil emergency storage program. The DOI report to Congress projects an investment cost of $1.20 per barrel for oil storage. It points out that $12 worth of oil can be removed from the stockpile and an estimated $1.20 invested in the storage facility can be saved for each 6 Mcf of new natural gas supplied from Alaska in the initial year of gas production (EP-231, p. 115). Considering both the cost of the oil inventory and the storage investment, the annual cost of storage, including carrying costs, could approximate $1.00 per barrel stored.

This is not to say that the oil storage program should be materially reduced because a substantial new natural gas supply is secured. What it does say is that if it is clearly in the oil consumers' interest to pay a substantial premium to protect continuity of supply, with the degree of self-sufficiency which that implies, it is also in the gas consumers' interest to do the same. To the extent that consumers can be insulated from the worst effects of future energy shortages or embargoes, the consumers and the nation as a whole benefit. Drastic reductions or interruptions in oil and gas supplies are more than inconvenient; they can impact swiftly and dramatically upon entire industries 1/ and on regional

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1/ Over 95% of the nation's ammonia-based fertilizer production presently depends on natural gas feedstock.

and national economies. 1/

Nor can the energy independence of the United States be considered solely on the basis of economics or energy costs; to do so in the face of continuing world energy cartels would be folly. Thus, even if a transportation system for Alaskan gas cannot be competitive with other fuel systems, there may be a clear need to secure this supply for U.S. economic defense. In fact, there may be a strong national interest in having in place the capacity to transport a larger volume of additional natural gas if unusual foreign pressure occurs. If one should take at full value the costs which the then-Secretary of State Henry Kissinger reportedly associated with the last oil embargo, 2/ the cost of additional in-place capacity may be a small price to pay to mitigate the impacts of such pressure. 3/ Since this gas supply is needed and in the public interest on traditional supply and marketability grounds, final resolution of this issue need not be reached.

B. Project Financing

Project financing is defined by El Paso (Financial Br. 6):

> Stated simply, a project financing involves the creation of a new enterprise which is financially self-sufficient. Stated in financial terms, the new enterprise is designed so that it generates sufficient revenues to pay its operating costs, to pay interest and principal on its debt, and to pay a return on and, ultimately, a return of its equity to its sponsors. Since the creditworthiness of the sponsoring pipeline companies is insufficient to attract the necessary capital to complete any of the three proposals, project financing supported by appropriate tariffs has been endorsed by all financial witnesses as the only reasonable approach to financing. Exhibit EP-254, p. 3.

1/ See, e.g., proceedings of January 20 and 21, 1977, in Docket No. CP77-116, Houston Pipe Line Company.

2/ See article in New York Times, October 19, 1976.

3/ Within this context, the trans-Canada routes have the advantage of cheaper in-place capacity, while the trans-Alaska route has whatever advantage results from being all-American and independent of Canada.

> The principal risk of project financing is that the project may not earn sufficient revenues to enable it to make the payments necessary to meet operating costs, debt service and payments to its sponsors. Assuming the underlying economic viability of the project, this risk could become a reality for three principal reasons: (1) failure of governmental regulation to permit the project to generate adequate revenues while in operation; (2) prolonged interruption of the project's operations or its abandonment; (3) non-completion of the project.

The following nondefinitive and somewhat simplistic statement is designed only to permit the uninitiated reader to more easily understand the ramifications of "project" financing. The usual commercial undertaking is nonproject financing and begins with a principal party (whether an individual, partnership or corporation) which is credit-worthy. The principal party provides a plan and the equity capital necessary to begin a project; the additional capital needed is then borrowed from lenders on the strength of the proposal's merit and the principal party's credit. A better mouse trap which gives the lender confidence in its marketability is a strong factor in convincing a lender that the entire project is financially sound. As the probable saleability of the product as a profit-maker deteriorates in the prospectice lender's eye, the quality of the principal party's credit increases in importance to him. The lender looks to the principal party to repay the borrowed money from definable and unencumbered resources. Absent other considerations not relevant here, as long as the lender is secure that his principal will be repaid and is promised and can secure a sufficient interest to cover those risks which he finds acceptable at the interest rate, he will provide money.

However, if the principal party is not sufficiently credit-worthy, the lender may look to the physical assets of the proposed project to protect his principal and interest. This is also project financing and also is not unusual. The principal party seeking credit in the typical arrangement structures the finances so that the project always includes a collateral interest--generally equity front-money recognized by the lender as providing security. Thus, as long as the debt from the lender is less than the property value which he would retrieve if he must look to a takeover, the lender can look solely to the project itself for security (e.g., a corporation mortgaging a building or a ship).

The situation faced by these applicants, however, represents what happens when the principal party is not sufficiently credit-worthy, the salvageable value of the project does not provide any significant collateral security to a lender, and the scale of the project is so large that (1) the principal party could not convince the same lender or other lenders to fund completion if there were overruns, (2) it might not profit the original lenders to complete the project if they stepped in to protect their position, 1/ and (3) the risk of not earning interest on the money, given the cost of money to the lender, is significant in itself. The proposed gas transmission pipeline in this case would have little salvage value and is poor collateral either prior to or after completion. It thus represents little security that a lender would recoup on his investment, principal and interest if it were necessary to exercise the lender's prerogative to step in to protect his position following a default. Similarly, the principal parties--gas transmission pipeline companies--are not collectively strong enough to enter open-ended commitments to the lenders to complete the project or to guarantee repayment of the debt. The lender, in other words, would be in no better position than the equity holder if there were a default resulting from noncompletion, since there is no equity cushion or collateral and no assurance of marketability of the product if he should be forced to take over the project.

The magnitude of the capital investment is such, therefore, that the gas transmission company sponsors cannot provide the institutional lenders with the degree of security necessary to warrant financing the project. The projects here, absent credit-worthy private parties, are arguably not susceptible to financing without reliance upon either the consumer or the taxpayer as the guarantor that the project will be completed and that debt service will be secure during sustained outages. Whether it is in the public interest to shift the traditional risks taken by sellers and transporters to the consumer or taxpayer is the significant issue.

C. Credit-Worthy Parties

1. The Producers and the State

It immediately became apparent that the only traditional credit-worthy parties involved in this proceeding whose added credit could permit conventional financing were the two direct financial bene-

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1/ The problem is twofold: risk of noncompletion and risk of sustained or permanent outage.

ficiaries of Alaskan natural gas sales--the producers and the State of Alaska. Despite the billions that each will reap from sale of Prudhoe Bay hydrocarbons, neither has shown any particular interest in investing in a transportation system to market gas or otherwise assist in its financing. The producers have been downright hostile to the suggestion. Along with frequent suggestions that the early agreements for Alaskan natural gas were necessary to rationally select a pipeline system, discussed supra, the producers have also been pressed to contribute their credit-worthy status by supporting the projects either through equity or debt participations, on the one hand, or guarantees on the other. The producers' resounding negative responses were punctuated by legal memoranda specifying their policy and constitutional objections to any arrangements linking sales or sale prices to such participation. As also discussed supra, on the merits the producers object to being forced to enter the regulated natural gas transmission business, 1/ claim a reluctance to expand their energy-oriented business while faced with divestiture proposals, and take the position that they are better off putting discretionary investment capital into nonregulated business ventures. Interestingly, several of the producers also pleaded poverty, since other investments, including nonenergy-oriented ones like Mobil's recent purchase of Marcor or Arco's purchase of Anaconda Company, have reduced both their available cash and their ability to undertake the level of guarantees which would assure lenders repayment of debt and equity. They assert that imposing investment in the project as a condition of their sales contracts would constitute taking property without due process.

The record does not indicate any financial help or encouragement given by the producers to any of these applicants in securing a gas transportation system. While at least two Canadian oil companies are still involved in plans to finance movement of Mackenzie Delta hydrocarbons, none of the U.S. companies have remained as part of any of these consortia. 2/ Nor, according to Governor Jay S. Hammond of Alaska, has the State seriously considered offering any of the applicants financial assistance (96/14,688).

1/ Such reluctance was not always the case. Recollection is that Pacific Northwest Pipeline Co. (predecessor of Northwest Pipeline Corp.) was the creation of Phillips Petroleum, and Gulf Oil spawned Transwestern. Even today Cities Service Co. and Tenneco Inc. have substantial interests in both production and pipeline functions.

2/ The Canadian companies are affiliates of U.S. companies. Several U.S. oil companies were part of the original Arctic Gas Study Group.

Realistically, in the time frame necessary to expeditiously finance these projects, the Commission is incapable of more than strongly suggesting to the producers that their financial assistance to these projects is both fair and proper and in their best interests. However, if the President and Congress deem it appropriate that the producers, as chief beneficiaries of the sale of Alaskan hydrocarbons, should participate in financing construction of a transportation system to market their product--a position pressed obliquely by the Department of Treasury representatives on the record and on brief--legislative methods may be pursued, as Treasury hinted, to secure such participation. 1/ If that should occur, many of the problems discussed below will become less significant.

As far as the State of Alaska is concerned, there is no record evidence that other states have participated in financing this type of gas pipeline project. It is not that financing utility and industrial projects through municipal bonds, direct ownership of generating facilities (e.g., New York), or forgoing certain taxes is unknown to states seeking to ensure an expanding economic base. Given the avowed intentions of the State to invest its revenues and the high rate of return suggested here for either equity or debt, the State may see this as a better investment than it can receive elsewhere. 2/ If, in addition, tariffs require the ultimate consumers to shoulder full debt service responsibility and the bonds issued achieve debt ratings satisfactory to the New York State Insurance Commission, they would probably also satisfy the

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1/ The corollary of not being able to make a horse drink when led to water is that you can make him darn sorry he did not.

2/ While it might be unkind to suggest, there is a likelihood that the State might be willing to aid El Paso if it appeared that such offer might tip the choice towards the State's first love. The State's excellent presentation, through a range of perceptive and knowledgeable witnesses, does not permit ignoring that such an obvious suggestion may be made at a propitious time in the decisionmaking process.

State of Alaska's investment trust fiduciary. 1/ Nevertheless, such investments are voluntary, and the State of Alaska has not volunteered.

2. Pipeline Sponsors

As already discussed, the pipeline sponsors, basically those which will purchase Alaskan natural gas and will have to contribute their equity and credit to construction of a transportation system, do not constitute a group sufficiently credit-worthy to satisfy lenders. While the identity of the specific group may vary depending upon actual sales contracts, as a whole this group will provide the equity capital to any successful applicant. The so-called "pro forma" applicants (the affiliates of the six pipeline companies comprising the Northern Border partnership) and the westcoast shippers combined do not have the financial strength to guarantee project completion. 2/ All the pipeline parties argue that the pipeline industry generally cannot guarantee, solely on the basis of their own balance sheets, that the project will be completed. Adding other pipelines, as suggested by Staff and Treasury, may make the combined balance sheets look better, but it is not apt to cure the problem. First, the pipeline sponsors will borrow substantial sums to raise the capital for equity contribution. The lenders will be aware that even if the pie is split 15 ways rather than 9, the total volume of debt money will be the same. Second, a number of the remaining pipeline transmission companies may not have balance sheets as strong as those of the present sponsors and could decrease the credit-worthiness of the

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1/ Neither the arcane workings of the rating services (i.e., Standard & Poor's or Moody's) nor the requirements of the New York insurance laws and insurance commission were explored. Decisions by both can have large and obvious impacts on every aspect of financing of these projects. If only to the extent these decisions affect these projects, they affect interstate and foreign commerce. The point is not pressed, but it seems curious that a decision reached privately or locally on a bond rating or the percentage of money that a regulated insurance company can invest in a particular foreign country should be so able to affect the national public interest without any federal scrutiny.

2/ The desirability of taking the risk, assuming that they were capable, is another matter, discussed infra.

project if they were added as participants. Moreover, as the required consortium of sponsoring parties grows, the conflicting demands they would make would create a more unwieldy arrangement And last, the existing sponsors state that even substantially reducing their equity participation would still leave high equity requirements which would not significantly change their policy decisions of their needs or lenders' view of the project as a whole. Collective strength, as stated earlier, shifts the question from guaranteeing project completion to an inquiry of whether the energy involved is so needed that the ultimate responsibility should be placed on the consumer or taxpayer rather than letting the project die.

The following discussion of all aspects of financing begins with this proposition: the delivered costs are such that the marketing remains questionable; however, the energy is needed and should be secured. To be successful, therefore, the project financing required here will require either consumer or government backstopping, or both, to guarantee project completion.

D. Field Price

The field price of Prudhoe Bay gas is not specifically at issue in this proceeding. No producer sales contracts--much less ones with specific prices in dollars and cents--have been made, and no sales applications have been filed. 1/ Moreover, as the producers and others have pointed out, the Commission has taken no action to establish a just and reasonable price for Alaskan gas. The record thus lacks any explicit assessment by either the owners or the regulator of the price at which this gas can or should move to market.

Nevertheless, projections concerning the price ultimately paid in the field, whether under federal regulation or free-market conditions, are crucial to any determination of the ultimate cost to the consumer. No confident findings respecting marketability or financeability are possible without such projections as the basis for reasonable assumptions.

The record is not totally devoid of information from which a preliminary evaluation of field price can be made. The DOI report to Congress estimated a total cost of about $0.47 per Mcf on the basis of a pretax cost of capital to the producers of 10%. 2/ The

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1/ The late-filed Alaskan royalty gas sales contracts are not, *inter alia*, price-specific.

2/ EP-231, p. 4; this cost included field facilities.

applicants and other parties have used illustratively a figure of $1.00 per MMBtu as the price in the Prudhoe Bay field. This illustrative figure reflects a consensus arrived at more-or-less independently, rather than an express agreement, and results perhaps as much from the ease of using a round number as it does from a general view that $1.00 per MMBtu might reflect the upper limit of the worth of the field gas. The only specific evidence of record on field price evaluation for North Slope gas was U.S. Navy testimony that $0.76 per Mcf was suggested as appropriate for sales of its current gas production in Petroleum Reserve No. 4 to the relatively nearby market at Barrow. The record does not disclose how that price was determined (78/11,899).

The field prices to be paid by shippers to producers for gas volumes delivered into the transportation system will reflect more than just the purchase of the commodity itself. Between the wellhead and the delivery point, there must be constructed an extensive gas gathering system and conditioning plant at a total capital cost, excluding interest during construction, estimated by the producers to be $1.8 billion. This cost, the producers aver, must be borne by the shippers. It is readily apparent that these facilities will not "cost out" at the few cents per MMBtu familiar from past area and nationwide rate proceedings. Producers have presented short-hand calculations, based upon the Arctic Gas project costs, suggesting that the unit cost of gathering and conditioning to be borne by the shippers will approximate one-half the unit cost of the transportation system (213/36,931 et seq.). 1/ One need not rely on these unsupported and untested calculations to realize that, given the magnitude of the capital investment, the unit cost will be high. All of these high transportation and field facilities costs are bad news for consumers--and for the producers and the State of Alaska.

The producers' difficulties in marketing this gas have been mentioned earlier. The field is far and away more remote from market than any other domestic supply heretofore attached. The transportaiton system to bring it to market is costed in multiples of the most expensive gas transmission line previously built. The gas will be produced as an adjunct to the production of oil, and its daily production rate will be determined thereby. Its unit value in the field, for example, cannot be favorably compared with

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1/ Thus, for example, if the transportation system were to cost $1.50 per MMBtu, the producers say gathering and conditioning will cost an additional $0.75.

production from fields in West Virginia, Michigan or California, located close to market where existing facilities can be used for transportation--or, for that matter, from fields in the lower-48 states generally.

These considerations have led some parties to question whether producers might be willing to accept a field price determined by backing off transportation costs from alternative energy prices in the market. The short answer to this question--and it cannot be emphasized too strongly--is that a field price for Prudhoe Bay gas established, by contract or otherwise, at a level higher than a value so determined, will sink this project. If the delivered cost of Prudhoe Bay gas is such that the high-priority consumers which constitute the market are prompted to turn to other energy supplies, the project is uneconomic. This is true whether the Alaskan gas is priced incrementally or on a rolled-in basis with other gas supplies.

No one should be misled into the belief that this Commission must fix, on an allocated cost-plus basis, a field price for Alaskan gas in excess of its intrinsic market value, that shippers would be obligated to offer to pay that higher price, or even that the Commission is under any duty to address the question of just and reasonable prices before the parties have come to terms. It is well settled under the regulatory scheme that prices are left, in the first instance, to the marketplace and that the Commission can reduce contract prices which are higher than just and reasonable, but that, absent circumstances of unequivocal public necessity, the Commission cannot raise contract prices that are lower than those that might otherwise be justifiable on the basis of cost plus a fair return. 1/ Given the facts that (1) the parties have not yet come to terms on price, (2) there is no Prudhoe Bay gas production experience or firm prospective production schedule, and (3) a large portion of the field costs remain to be incurred, it is hardly surprising that the Commission has remained silent.

Against this backdrop, a few observations are in order. On the basis of 1975 dollar costs, the Marketability section, supra, shows that Alaskan gas with a field price of $1.00 per MMBtu is marketable even on an incremental cost basis. The delivered city-gate cost of Alaskan gas (based on Arctic Gas' transportation cost estimates) is $2.41 per MMBtu (simple average for the eight market areas shown), as compared with $2.61 for distillate fuel oil, $2.59

1/ Natural Gas Act, §5; United Gas Pipe Line Co. v. Mobile Gas Corp., 350 U.S. 332,341 (1956); Permian Basin Area Rate Cases, 390 U.S. 747, 820-822 (1968).

for residual fuel oil and $6.89 for electricity. These figures ignore the pricing premiums which natural gas would command. If one assumes that 1975 dollar price relationships between competing energy supplies will continue in the future, that natural gas has a premium value of $0.65 per MMBtu, 1/ and that the actual cost experienced for the transportation system will be $2.00 per MMBtu in 1975 dollars (i.e., that substantial cost overruns will occur), Alaskan gas with a field price of $1.00 per MMBtu would prove to be marketable on an incremental basis. 2/

The sum of all this is that $1.00 per MMBtu at the inlet of the transmission system (i.e., after gathering conditioning) is, in all likelihood, close to the maximum that this gas could command in the field and still be marketable under present market conditions. Whether that level is more or less than what the Commission might some day determine to be just and reasonable to the producers on the basis of some theory of allocated cost plus fair return is unimportant for present purposes. However, depending upon the ultimate costs of the gathering system and conditioning plant, as well as the allocation of those costs between pipeline gas and the large volume of removable liquids, there would nevertheless appear to be a substantial return to the producers from a total field price at or below $1.00 per MMBtu. 3/

1/ Witness Schantz at 174/28,674-28,675 using EP-231 data.

2/ Regardless whether shippers should be required by the Commission to price Alaskan gas incrementally or be permitted to roll-in Alaskan gas prices with prices of lower-48 gas, prudence as well as good economic practice requires marketability to be tested on an incremental basis.

3/ Given the unprecedented anticipated costs for gathering and conditioning, the Commission should insist that it be permitted to review all decisions on the need for and the cost of gathering and conditioning. It is recognized that the Commission has no direct jurisdiction, but this review should be a condition for approval of any sales contract containing any provisions, directly or indirectly, for gathering and conditioning charges. See PSC of New York v. F.P.C. 287 F2d 143, 146, supra.

E. Rate of Return

Just as the field price of natural gas cannot be fixed in this proceeding, neither can the cost of debt capital be presently predicted. Nor can a definite rate of return on equity be fixed at this juncture. The issues nonetheless must be discussed. The applicants' financial witnesses estimate a debt cost of approximately 10%, based on a Baa bond rating, and the applicants seek 15% to 17% as an after-tax return on equity.

The proposals or predictions made here for high rates of return represent a frontal assault on the accumulated wisdom of untold centuries of financing, which wisdom equates return and risk in such a way that they rise and fall in tandem and roughly proportionately. As perceivable risk goes up or down, so does anticipated return. But not for an Alaskan gas transportation project, say the experts--the 49 financial witnesses of the applicants. 1/ No matter what is guaranteed or how the guarantee is framed and regardless of the responsibility of the consumer or taxpayer, the projected rates of return here can be expected to remain high. So they say.

As is decided infra this section, rate provisions for the shipment of Prudhoe Bay gas to lower-48 markets should contain not only a full cost-of-service tariff but also a provision to protect lenders against the risk of noncompletion. Also sought by applicants are legislation to protect the flow-through of charges to the consumer and/or federal financial guarantees. With such regulatory and/or statutory devices in place, the risk for debt service would be minimal, the bonds would be well rated, and the interest rate should reflect those conditions.

The range of equity return sought by the applicants is roughly 2 to 3 percentage points higher than the highest rate of return previously approved by the Commission for pipeline companies when the equity holder takes substantial risk; it matches and exceeds the level allowed in area and nationwide rate cases for the relatively more risky activities of gas producers. Nonetheless, the managements of prospective pipeline company shippers seek substantial protection of their equity investments, such as the ability to write those investments off through charges to operations in the event the project founders.

1/ The proper relationship is recognized, however, by Treasury witnesses Niehuss and Barnhill and Staff witness Anthony Jiorle.

As already stated, setting a specific rate of return on equity at this time would be capricious. The level of risk on equity cannot be known until the ultimate decision of what protection, if any, should be given the equity holder is reached. Setting a specific rate of return, therefore, can only be accomplished in the next phase of this case, by which time the degree of risk to be borne by equity investors will have been resolved, the successful applicant will have a definitive financial plan, and financial market information more current to the period of actual capital formation will be available. Notwithstanding this decision, several prefatory observations are appropriate.

The highest rates of return on common equity allowed by the Commission in recent years for interstate gas pipelines are 13.50% and 13.75%. 1/ Although these pipelines were not laboring under the risks inherent in constructing and operating an Alaskan gas transportation system, neither did they have the degree of insulation from risk sought by equity investors in the Alaskan project. In addition, unlike these existing pipelines which are faced with recovering substantial fixed costs from rapidly declining gas supplies, the Alaskan gas project will have the decided advantage of a vast new source of supply which should assure reasonable amortization of the fixed costs over the life of the project.

In light of the finding made herein that neither return _of_ nor return _on_ equity should be allowed in the event of project noncompletion or sustained or permanent outage, it is reasonable to recognize the degree of risk assumed by the equity holders; therefore, some increment above these previous high pipeline rates of return may be warranted. However, a range from 14% to 15% would certainly appear to be the upper limit. If, however, it is ultimately decided than even partial return of equity should be protected if noncompletion or abandonment occurs, then a much lower range is mandated: 12% to 13% appears reasonable at this juncture. And if return _on_ equity is also protected, the rate of return should be even lower, since "equity" would then have lost all meaning as descriptive of the investment.

F. Incremental v. Rolled-In Pricing

It is appropriate at this point to lay to rest the lurking issue of whether the Commission should require regulated pipeline shippers of Alaskan gas to sell such gas to distributors under

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1/ _Natural Gas Pipe Line Co. of America_, Opinion No. 762, issued May 21, 1976; _Tennessee Gas Pipeline Co._, Opinion No. 769; issued July 9, 1976.

separate rate schedules and contracts, i.e., incrementally, or permit the cost of Alaskan gas to be averaged by the pipelines with the costs of their other gas supplies and sold on a rolled-in basis under existing rate schedules and contracts.

The applicants and the putative shippers all support rolled-in pricing, as does the California Commission (CPUC Wrap-up Br. 10). Sierra Club urges incremental pricing (Statement dated December 3, 1976). 1/ New York PSC states, as one of many suggestions, that, rather than burden existing consumers with the project risks, it would be appropriate to consider federal legislation to free the gas for sale to the burner tip on an incremental basis (New York PSC Comments on Financial and Tariff Briefs, 3). Staff would defer the issue to the next phase of the case (Ans. Tariff Br. 24). Dr. Schantz supports rolled-in pricing. He states such is consistent with Commission regulatory treatment of other gas supplies produced in the United States. The witness points out that the Alaskan gas will replace, not supplement, declining production of gas in other areas of the United States to maintain service to residential and commercial consumers, that gas distributors universally serve these consumers on a rolled-in basis, and that it is far-fetched and improbable to expect a change in such practice in the future (174/28,656-7).

FEA takes no position on this issue (158/26,024). Dr. Jon Goldstein of the Commission Staff, while not specifically proposing the incremental pricing of Alaskan gas, describes theoretical economic drawbacks to rolled-in pricing. Essentially, such procedure could result in one class of customers--those using lower-priced gas from the lower 48 states--subsidizing another class, those consuming Alaskan gas; in addition, rolled-in pricing could give an incorrect "price signal" which would result in higher gas consumption than if the consumer were faced with the full marginal cost (148/24,041, 24,082, 24,089, 24,095). 2/ The witness concedes, however, that the prospect of subsidy is mitigated to the extent the Alaskan gas is delivered to the same customer group receiving the diminishing lower-48 supply (148/24,071-80). In any event, he recognizes that avoiding the possible problems he perceives in rolled-in pricing cannot be assured by the Commission, since the Commission's jurisdiction does not extend to the burner

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1/ Virtually all of the argument of Sierra Club is embodied in a monograph, which is not in evidence, authored by an economics professor who was never called to testify.

2/ See also Ex. EP-231, pp. 64-65.

tip (148/24,042). Incremental pricing is not without its problems (148/24,083, 24,091, 24,100-101). 1/

Regarding domestic supplies of gas, the Commission has followed the "time-honored tradition" of rolling-in new gas prices with the old ones while letting all customers pay their pro rata share of the costs of the supplement. Columbia LNG Corp. v. F.P.C., 491 F.2d 651, 654 (D.C. Cir., 1974). This is premised on the regulatory principle of assuring "equal treatment for customers receiving equal service." Battle Creek Gas Company v. F.P.C., 281 F.2d 42, 46 (D.C. Cir., 1960).

While the Commission may not be legally barred from requiring that regulated pipeline shippers of Alaskan gas resell that gas to distributors under separate contracts and rate schedules, such requirement must reflect findings based upon substantial evidence which justifies departure from the longstanding Commission practice. Columbia LNG Corp. v. F.P.C., supra. 2/ As was the case in that proceeding, there is little or no evidence of record here which addresses the administrative problems involved in incremental pricing, what the cost of implementation might be, or whether the public interest would be better served by imposing such a pricing condition.

More specifically, no group of distributors has been identified which is agreeable to purchasing Alaskan gas on an incremental basis. 3/ Even if it is assumed that all the distributor customers of the prospective pipeline shippers were willing to purchase on an incremental basis, their acquiescence would not be translated into incremental pricing to ultimate consumers (the premise

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1/ See, e.g., Columbia LNG Corp., 48 FPC 723,729.

2/ There is a serious doubt that incremental pricing would be legally defensible if it resulted in widely disparate rates for similar customers (Columbia LNG Corp. 48 FPC at 737-8).

3/ Treasury witness Niehuss has suggested the possibility that a portion of the Alaskan gas be sold directly on an incremental basis to industrial consumers who would participate in project financing. Aside from the question of how such a proposal would be compatible with the public interest of reserving natural gas for higher-priority uses, no willing industrial group has been identified.

of Dr. Goldstein's theoretical economic presentation) unless they departed, with state regulatory agency approval, from their universal practice of rolling-in their costs of purchased gas in setting rates for customers. When, as here, the new gas supply will simply replenish the diminishing existing supply in high-priority markets, incremental pricing to the burner tip would merely introduce unnecessary and avoidable administrative problems which this Commission should not encourage. 1/

Moreover, deferring this issue to a subsequent phase of this case can only further imperil, if not frustrate, the timely financeability of an Alaskan gas transportation system. Accordingly, on the facts of this case, it is found that incremental pricing should not be imposed by the Commission.

1/ For a like disposition of this issue in a similar proceeding, see El Paso Natural Gas Co., Docket No. CP73-131, Initial Decision issued June 21, 1974. See also Columbia LNG Corp., Opinion No. 786 issued January 21, 1977, endorsing rolled-in pricing on the merits in that proceeding after remand in Columbia LNG Corp. v. F.P.C., supra.

G. Financial Plan Feasibility

Given the above discussions and the different guidelines that are certain to be in place when the successful applicant seeks to firm up final financial plans for Commission approval, the detailed record discussion of the feasibility of existing plans takes on less significance. The successful applicant will be required to come forward with final financial plans for Commission approval which will take many months to prepare and which may not closely resemble the original proposal. Nonetheless, the mechanics of applicants' present plans are set out below and an analysis is made in the appendix of the feasibility of each applicant satisfying its capital requirements from the various debt and equity markets considered. In the analysis of the capital market capacity, adequate identical security provisions are assumed, and the engineering and operational differences among the projects are ignored. Furthermore, increases in real costs from cost overruns or design changes mandated in this Decision, supra, are not considered.

The financial plans of the three applicants are previewed below in the following tables with appropriate notes. While some attempt was made to place these plans on a comparable basis, a distortion has resulted from the fact that, while Arctic Gas and El Paso stated their requirements on a 1975 dollar basis, Alcan elected to show requirements on the basis of an assumed inflationary cost escalation through the year of construction. Thus, if for no other reason, the $8.5 billion for Arctic Gas and the $6.0 billion for El Paso cannot be compared with the $12.3 billion figure for Alcan-Maple Leaf. In any event, the tables are intended to be considered in conjunction with the financial appendix hereto (Appendix I), are not otherwise fully comparable, and are primarily included for the purpose of giving a general overview.

ARCTIC GAS (Source of Funds at Completion) 1/
($ Millions)

	Alaskan Arctic	Canadian Arctic	Northern Border	PGT & PG&E 2/	Trans-Canada 3/	Total
Banks 4/						
U.S.	132	311	192			635 5/
Canada		500				500 6/
Long-Term Debt						
U.S.	315	1,850	603	508		3,276
Canada		850 7/			694	1,544
Export Credits		500				500
Euro Credit Bonds		200				200
Equity						
U.S.	150	699	267			1,116
Canada		701			49	750
TOTAL	597	5,611	1,062	508	743	8,521 8/

1/ This does not include interim or bridge financing and therefore requires less capital than will actually be needed in the aggregate over the construction period.

2/ PGT and PG&E were not considered by Arctic Gas but are in this table; although project financing might not be required for the 1580 design, this western leg is an integral part of the project as a whole. Alcan includes PGT and PG&E.

3/ Arctic Gas excluded the financing requirements of Trans-Canada. These capital costs of enlarging Trans-Canada to handle Mackenzie Delta gas transported by Canadian Arctic must be considered for financial analysis. The same applies to Alcan and Maple Leaf, infra.

4/ Arctic Gas plans $1,750 million of Eurocurrency bank loans, $850 million of which would come from non-North American banks.

5/ As indicated infra in Appendix I, Arctic Gas actually plans to seek loan commitments from U.S. banks for $1,592 million, including $400 million for Canadian Arctic standby commitments and $400 million for U.S. bank participation in Eurocurrency loans.

(Footnotes continued on next page)

EL PASO (Source of Funds at Completion) 1/
($ Millions)

	Alaskan Facilities	LNG Fleet	Western LNG	East of California	Total
U.S. Border	270 2/				270
U.S. Life Insurance Cos.	1,600 3/		528	217.8	2,345.8
U.S. Pension Funds	400	1,049.2			1,449.2
Debentures	250				250
Equity Sponsorship	1,031.4	427.1	155.4	72.5	1,686.4
TOTAL	3,551.4	1,476.3	683.4	290.3	6,001.4 4/

1/ This was the only financial format proffered by El Paso. It understates the true financial requirements because it does not include any interim or bridge financing.

2/ This $270 million is the outstanding balance of El Paso's $1 billion revolving credit agreement which would be converted into a term loan. Moreover, Western LNG plans to make short-term bank borrowings of $150 million.

3/ Not shown here is $350 million in capital notes which El Paso would sell to the sponsors in lieu of common equity. They are described and rejected in Appendix I.

4/ With AFUDC, this total is $6,500 million (1975 dollars). No contingency financing has been included by El Paso.

(Continued from previous page)

6/ Appendix I also shows that Arctic Gas actually plans for $600 million in term-loan commitments, $200 million in bridge-loan commitments, and between $400 and $500 million in Canadian bank participation in Eurocurrency loans.

7/ $350 million to be privately placed with insurance companies and $500 million publicly placed.

8/ This total does not include any contingency financing, and it represents 1975 dollars.

ALCAN (Financial Requirements)
($ Millions)

	Alcan 1/	PGT PGE	Northern Border	Sub-Total	Foothills (Maple Leaf)	Trans-Canada	Total
Banks							
U.S.	567		275	842	230		1,072
Canada	576			576	420		996
Long-Term Debt							
U.S.	3,186	508	871	4,565	545		5,110
Canada	965			965	725	694	2,384
Equity							
U.S.	991		382	1,373			1,373
Canada	735			735	640	49	1,424
TOTAL	7,020	508	1,528 3/	9,056	2,560	743	12,359 2/

1/ Includes Alcan, Foothills (Yukon), Westcoast, AGTL, and Northwest.

2/ Alcan would reduce this to $11,919 million to account for claimed duplications of $440 million. In addition, Alcan would increase the total financial requirements to $14,576 million by including contingency requirements, which are made up of $1,197 million for the Alcan group, to be raised from the same capital markets as noted above, $370 million for Northern Border, and $820 million for Foothills (Maple Leaf).

3/ Alcan apparently has included the costs for Northern Border as originally designed. Arctic Gas ascribed capital costs of $1,062 to the truncated Northern Border design. There are no costs for a redesigned Northern Border compatible with the Alcan proposal.

Operating under these foregoing caveats, financing of the El Paso project appears on its face to be the most feasible, even though certain provisions must be altered. 1/ The Arctic Gas project can also be financed, but capital cost premiums and financial restrictions, inherent in its binational make-up, produce less flexibility and higher capital costs. In light of the close nexus between the Alcan and Maple Leaf projects and the strong possibility that both might have to be financed at the same time, there are serious doubts as to the feasibility of financing Alcan. It has previously been determined that slippage in the Alcan schedule is unavoidable. This would force simultaneous financing of the two projects, unless Canada were willing to accept long-term deferral of reaching its Mackenzie Delta gas. Alcan cannot be financed on this basis. If Maple Leaf is not in the picture, there appears to be adequate market capacity in the U.S. and Canada for Alcan to obtain financing. Only when the Alcan and Maple Leaf projects are financed and constructed on a sufficiently staggered scheduled do Alcan's own financial requirements not surpass the capacity of the Canadian and U.S. capital markets nominated in its financial plan. Alcan's own financial requirements do, however, strain that capacity. While Alcan espoused a 13- to 22-month timing gap between projects as a minimum to avoid direct financing competition, the investment and lending communities could well require actual Alcan operations and cash flow before the construction of Maple Leaf to avoid the aggregation of the capital requirements of the two projects. This would mean at least a 4-year timing difference.

One last observation is necessary here. El Paso, as an all-U.S. project using only traditional U.S.-money markets to raise its funds, will be able to do so easier and more cheaply than either Arctic Gas or Alcan. It also has the distinct advantage that inures to it from building U.S. ships under U.S. loan-guarantee incentives. Arctic Gas has optimistically evaluated its supply markets, has optimistically assessed how it views its worth to the financial community, and has injected several innovative proposals, only partially tested, to spread its choices and not overburden the credibility of its suggested scheme. This does not, of course, make its financing impossible, but since uncertainty is the nemesis of easy financeability, it makes it susceptible to higher costs because of unknown and unquantified risk. Arctic Gas' financial plan, therefore, cannot be found to be as easily financeable as El Paso's.

1/ Some parties believe, however, that the El Paso project, given its route and technological complexities, would not be well received in the financial markets. (See, e.g.,Wisconsin Position Brief, p. 6.)

H. Tracking

El Paso holds to the belief that an Alaskan transportation system can be built without federal financial guarantees. Its proposal hinges, however, upon two conditions. First, the Commission must authorize an all-events cost-of-service transportation tariff and preoperational surcharge provisions in shippers' tariffs, requiring that the consumer assume virtually all risks if noncompletion or sustained outage occur and must also amend the FPC-regulated pipeline purchasers' tariffs, the only purchasers contemplated under the proposal, to require that all costs be shifted by state-regulated distributors directly to the ultimate consumers. Second, the pipeline purchasers must accept El Paso's theory that, under existing law, such consumer guarantees could not be substantially modified by future Commissions and that legal remedies exist for expeditiously limiting state interference in the flow-through process. As noted, the Staff opposes the first condition, and the prospective pipeline purchasers have stated on brief that they distrust any theory based on the present state of the law which would preclude future Commissions from modifying the tariffs and also prevent individual state utility commissions from frustrating timely collection of funds.

El Paso's theory of the likely ultimate legal consequences, 1/ while having substantial merit, can be given no practical credence. 2/ The very companies that it must rely upon as shippers

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1/ El Paso argues persuasively that disallowance in state rate proceedings of amounts paid for gas by a local distributor, when such amounts reflect a supplier's rates subject to the FPC and approved thereby, would be held unconstitutional. Citing a plethora of relevant cases, it contends that such action would constitute (1) a violation of the due-process clause of the 14th Amendment and (2) a collateral attack on a valid federal order in derogation of the supremacy clause. The El Paso argument that actions taken by the present Commission are binding on future Commissions, while well documented, is based on a theory that no finding of "changed circumstances" is possible, and is less persuasive (Regulatory Action Br. 21-33).

2/ See, e.g., Columbia Gas and Texas Eastern briefs dated September 3 and September 9, 1976, respectively.

to make its plan work are fearful of litigation delay and the consequences of a misstep in an area clearly not favored by regulatory philosophy. Columbia states flatly that it "...would not be able to agree to El Paso's Investment Recovery Proposal"(Id. p. 4). It is convinced that commitments based solely upon existing regulatory approval, no matter how favorable, are unacceptable and unworkable for it and the financial community. 1/

There is an additional problem with El Paso's basic reliance on pipeline purchasers' flow-throughs of costs. In a separate brief, the State of Alaska challenges as unsound that portion of El Paso's financial plan which would limit gas purchase participation to regulated natural gas pipelines. Arizona also addresses this aspect of El Paso's plan in its Position Brief. Alaska's opposition is based upon its view that the State ultimately intends to sell its royalty gas to intrastate users and that, under the El Paso financial plan, such users would be precluded from gas purchases. This is a rather interesting twist, since the State's request to broaden the list of potential purchasers, if adopted, could unhinge the entire El Paso plan, even if it were otherwise workable. Excluding up to 12½% of the total supply from the federal regulatory guarantee would require that the remaining 87½% of the supply absorb that responsibility and obligation.

Another aspect of the State's interstate contracts with three existing pipelines, which already reduces the ability to finance, is the State's determination to include withdrawal provisions--provisions which now appear sanctioned by section 13(b) of the 1976 Alaska Gas Act. Forgetting for the moment whether any of the three royalty gas purchasers agreeing to such withdrawal and now favoring El Paso's proposal could obtain lenders' support for their portion of the project, these withdrawal provisions raise questions of whether the rest of the interstate pipeline shippers, buying producer-owned gas, could obtain financial support with those provisions operative in the royalty gas sales contracts. First, the withdrawal would idle pipeline capacity between the intrastate point of use and the ultimate destination. The State has graciously offered to pay for transportation capacity from the field to the intrastate point of use, but has not offered to pay either the transportation company or specific contract shippers for their higher costs of moving smaller volumes of gas through what would

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1/ Notwithstanding El Paso's legal arguments, it is understandable why it is very hard for these companies to believe that the courts would not find a way to avoid applying estoppel to a future Commission--particularly since the predicate of such agency action would have to be a clear finding that failure to set aside the prior agency action would result in harm to the public.

then be an oversized downstream system.[1/] Assuming that other, additional gas were available for shipment, someone else would assume the capacity--e.g., increasing a portion of El Paso's upstream pipeline flow past 2.4 Bcfd to achieve the volumes necessary to efficiently run the downstream facilities. If Alcan were the transporter, it would have to add uneconomic compression or start looping, raising a question of whether rolled-in or incremental pricing would be more equitable for short-haul costs. It is the "ifs" which make financeability a problem, and this would surely create a large area of uncertainty. Thus, including intrastate customers removes federal regulatory tracking guarantees from the financial package and weakens it substantially. This is true whether withdrawal occurs now or 10 years from now. See also legislative recommendations in the Potpourri section, infra.

Regardless of the resolution of the State's position, the fact is that regulatory provisions necessary to provide consumer guarantees of the project would require federal legislation, just as surely as legislation would be required for federal monetary guarantees. The legislation would lock tracking into place and prevent state interference with the regulatory scheme approved by the Federal Power Commission. Treasury supports this approach. See infra., Consumer v. Taxpayer Guarantees.

If it is assumed arguendo that El Paso's theory is practicable or that appropriate legislation locking tracking in place were passed, it is then reasonable to examine the second aspect of El Paso's proposal under its Investment Recovery Charge system. What it requires is that debt service would be permitted "even should the project fail of completion or operation" (El Paso Regulatory Action Brief of June 4, 1976 p. 11). The assurance aspect causes concern not only from philosophical and regulatory questioning of whether it should even be permitted for an operational pipeline under a tariff, but also as to the question of whether costs associated with a not-yet operational pipeline could or should be passed on to anyone. All of the applicants and Treasury argue that the former is necessary for any financing (discussed in the Consumer v. Taxpayer Guarantee section, infra).

1/ In a separate brief, the State avers that it no longer seeks the producers' agreement to underlifting, so long as section 13(b) is in place. "Underlifting" is the provision of a joint operating agreement whereby each party can take its share of the oil or gas in the reservoir independently of the other parties and, if any party fails to take or takes less than its proportionate share, to allow the taking party to produce its respective share of the reservoir oil or gas at a faster rate.

El Paso asserts that mechanically all that is entailed is an on-site continuing audit with timely Commission approval of prudently incurred costs so that they can be reflected in shippers' tariffs on a current basis. Staff takes the position that no construction costs incurred should ever be approved prior to completion because the Commission would not have been able to determine prudence of cost incurrence unless the Commission were able to review the entire project before it went into service. An "imprudent" act of an employee at the tail end of construction, under the theory espoused by Staff, could vitiate the entire previous investment. Staff supports this position first on the doctrinaire basis that under rubrics such as respondeat superior and that the project owners are responsible for their own actions, it is logical, which it may well be. Staff's second argument is that Section 4 of the Natural Gas Act, requiring final Commission approval of all costs before being included by a pipeline in its rate base, has been in place for years; that there will be no surprises at the last minute since a continuing audit will be in effect; and, if there were an abortion of the project, applicants could then request amortization of investment under the standards of the Act.[1] In essence, Staff ignores completely that the uncertainty generated by its position is totally impractical. No one is going to gamble $5 billion or more on any project with even the remotest possibility that an unknown Commission, in possibly a not yet conceived agency, might have a strange notion of imprudence or different concept of what could be amortized. Much of the decision as to the amount to be amortized would be discretionary, moreover, and all of the rest of the issues would be subject to litigation. There is nothing wrong, inherently or practically, with El Paso's mechanical proposal to have periodic approval of construction and related expenditures, whether or not consumer guarantee of debt service is permitted for that period before the tariff is operative and the project becomes a "natural gas company". See discussion, infra.

Whether the consumer should bear these costs is discussed in the next section. Suffice it to say, if El Paso's theory is correct about flow-through or if legislation were passed to overcome the inability of pipeline shippers to track construction costs through their tariffs, the matter is one of policy and not of law. See Consumer v. Taxpayer Guarantees, infra.

1/ Staff in its Commission Tariff Brief, p. 5, appears to mean debt and equity. In all likelihood Staff would oppose such amortization since an aborted pipeline on its face could be argued to have been imprudent.

I. Consumer vs. Taxpayer Guarantees

As previously indicated, the financial community views these projects as risky, and the applicants' financial witnesses uniformly took the position that a number of regulatory innovations must be instituted to shift various risks, normally borne by the equity-holder and lender, to the consumer. The alternative is taxpayer guarantees, which a number of parties view as necessary in any case; however, they would be lower if consumer guarantees are also operating (Arctic Gas Financial Br. p. 5). 1/ These philosophical and policy decisions, as well as the mechanical rate and tariff modifications, include the "all events" cost-of-service transportation tariffs, protection of debt service against preoperational project abortion, and modification of regulated shipper tariffs to permit direct flow-through of transportation charges to the distributors and then the consumer.

In addition, the managements of prospective shippers generally seek approval of some mechanism in their tariffs to generate cash flow during the construction period to cover the cost of financing their enormous equity investments in the transportation system and to assure that such equity investment would be recovered from their customers if the project collapsed at any stage. As set out above, the general form which the transportation tariff provisions would take, if approved on policy grounds, was worked out during the hearing and submitted as pro forma tariffs by each party.

Staff's position, basically supported by California and New York, is succinctly summed up in Staff's Financing Brief as follows (p. 8):

1/ Arctic Gas states in its Initial Financial Brief (p. 3):

> the severe practical problems encountered in obtaining assured regulatory devices so buttressing the credit of those parties giving such assurances as are required to satisfy lenders, equity investors and shippers, are such that complete success is uncertain, and in any event so time consuming, that the more practical and expeditious means of financing within a reasonable time frame may be to secure strictly limited government backstopping against the remote contingencies of non-completion and permanent interruption.

> The record in this proceeding supports the adoption of a cost of service tariff to accommodate the revenue generation needs of project financing. Staff's tariff proposal will permit revenues to be collected by the project company to meet all of its cost requirement during normal operations. At times of interruption of delivery, the tariff will permit the project company to collect revenues that will meet debt service , since the revenues will be lowered to reflect only the non-allowance of costs for equity and for related taxes. Under this recommended cost of service tariff, project financing can and should proceed under normal conditions. However, because of the lack of financial credit-worthiness of the present sponsors, further abnormal requests are made. 1/

After then stating that the Staff was "aware that some major lenders may not be satisfied with the mechanism proposed [by Staff]", it concluded that "the record does not justify a prior commitment be made to allow debt service to be flowed through to customers in the event of non-completion." Staff's position is that only normal financing procedures should be used to test the viability of this project. It considers the producers as logical participants in financing but recognizes their unwillingness to contribute. It then argues that, if the individual pipeline sponsoring companies have extended their financial resources beyond their ability to finance, they should bring in additional companies until the consortium seeking a certificate can provide traditional financing. See supra.

Both New York and California argue that producer participation as equity contributors should be forced and that it is outrageous that, as the chief beneficiary of the project, they have not voluntarily come forward to shoulder their burden (e.g., Calif. p. 17). Putting this aside, New York then states (Supplementary Tariff Br. p. 1):

1/ Staff seems to suggest that applicants' tariffs, with Staff's specific modifications, would bar recovery of equity capital during periods of interruption. The Presiding Judge reads the tariffs differently, as apparently does New York (Tariff Brief p. 7).

> ...New York cannot endorse a project which is only feasible if existing gas consumers, who may never benefit from it, must assume a major share of the initial financing responsibility, and must oppose any project in which future gas consumers are called upon to bear substantial risks of non-completion.

And at page 3:

> We reiterate our view that no project should be finally approved except upon a finding that it would continue to be economically viable in the event of substantial cost overruns, and that if this is the case, the primary completion problem will be to ensure the availability of the additional funds necessary to finance such overruns. This is the kind of guarantee that the Federal government is peculiarly equipped to provide at little ultimate risk to the taxpayer. It is possible, as Treasury has suggested , that responsibility for assuring cost overruns could be assumed or imposed upon the Alaskan producers. We are convinced, however, that it would be extremely unfortunate to accept such a proposal in lieu of direct producer participation in the debt or equity financing of the project.

Both N.Y. and California strenuously oppose shifting the risks of the project to the consumer, noting that this is the ultimate reversal of the regulatory process "from a method to protect the consumer from the economic power of the industry into a proceeding to require gas consumers to protect the industry from the risks of the potential enterprise" (N.Y. Tariff Brief, p. 2).

In fact, on tariff and finance issues, as well as other matters, nearly one-third of the states have participated from time-to-time. 1/ For the most part, they either support the California

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1/ Arizona, California, Kansas, Iowa, Maine, Michigan, New Hampshire, New Mexico, New York, North Carolina, North Dakota, Oregon, Washington, West Virginia and Wisconsin. The positions of many were copied into the record (120/19,184-220) while others, like Arizona, California, New York, and Wisconsin filed full briefs.

Alaksa, California and New York in particular have actively participated in this case, and their contribution has been very helpful.

and New York view or, like the State of Washington, indicate that state laws provide a right to review any local utility tariff seeking to pass through any transmission costs to their constituents.

Treasury also begins with the proposition that the chief beneficiaries--the producers--should be made to participate in financing the needed facilities. Treasury, like those who think such producer participation is in the public interest, calls for a combination of methods which would both lock in the consumer and, in some vague manner, force or entice the producer to participate. It argues that the consumer can be protected through appropriate regulatory devices, even if a guarantor, and urges that the taxpayer should not be called upon as guarantor because of a range of undesirable consequences which would result from that step.

Attacking as basically uninformed those who think that a "least difficult" solution would be a government guarantee, Treasury catalogues the difficulties such legislation would encounter--including Treasury opposition. It summarizes the list of undesirable consequences as follows (Br. p. 15):

> Moreover, even if more expedient for project completion, Federal financial assistance--admittedly seductive in a short-term context--on balance must be resisted as contrary to the public interest in the long run. Tr. 250/43,763-64 (Niehuss). Treasury testimony indicates why:
>
> --Federal assistance could prevent "the efficient allocation of resources that results from the action of private market forces."
>
> --As a result, "consumers could face the prospect of paying a very high (non-economic) price for the gas once the system is completed."
>
> --In addition, "other more economic projects might not be undertaken in a timely fashion, and the nation could suffer a significant net economic loss."

--Finally, serious long-run dangers include "(1) reducing the willingness of private parties to support major projects in the absence of government financial assistance and (2) increasing the degree of government involvement in the energy industry." Tr. 250/43,606-07 (Niehuss)

Thus, Treasury directly attacks Arctic Gas, its pro forma shippers and the various states which all attempt to make an equitable case for government guarantees as well as or rather than consumer guarantees.

El Paso assumes consumer guarantees. By maintaining that its project can be financed by regulatory approval of flow-through to the consumer in the individual tariffs of the regulated pipeline transmission company shippers (its Investment Recovery Charge proposal discussed above) it argues that it is the only applicant that can be financed without Treasury backstopping. Arctic Gas views the Investment Recovery Charge scheme as unworkable as presented, but argues that even if El Paso were right, it would be easier to finance the Arctic Gas project by that arrangement, since it views itself as the stronger applicant.

Interestingly, all the applicants and the Treasury Department view Staff's position and the various states' positions as limited and lacking a full appreciation of the needs displayed on the record for the consumers to assume the residual financial risks. 1/ Treasury in particular attacks Staff's position as having limited horizons philosophically, suggesting that it is not "presumptuously unreasonable" for the ultimate beneficiary-- the consumer--to share in the financing, as long as the "...consumers are...adequately protected." Treasury reviews the evidence of the key applicants' financial witnesses and concludes that El Paso supports Treasury's position and that neither Arctic Gas' nor Alcan's witnesses categorically espoused the need for government financing if legislation could overcome the shippers' fear that future agencies could interfere with tracking. Then, as already stated, Treasury argues that the consumer, not the taxpayer, is the only direct beneficiary, and it suggests any number of various surcharges and financial insurance schemes which will give the consumer a reduced ultimate price for assuming risks normally taken by the principal parties.

1/ While all parties agree that project failure is a remote contingency, they all agree that removing this risk is nonetheless critical to financing.

There is little question at this point that for any of these projects to be financed, the risk of debt service must be shifted to either the consumer or the taxpayer. There are no sufficient credit-worthy and willing private parties. In final analysis, the cost of guaranteeing the undertaking represents too large a share of the applicants' corporate net worth. Reducing the shares and spreading the risk to others is not feasible, since it is unlikely that even the total pipeline industry has the resources to "put on the line." As a policy matter, moreover, they cannot commit these large resources without earnings for the period of time necessary--5 to 10 years--without severely limiting their ability to finance other ventures to replenish their energy reserves. The risk--no matter how remote--that they may be required to produce large sums of money to complete the project also creates uncertainties of future financial requirements in unknown financial times. 1/

Accepting the collective position of the Staff and several of the states that no risk should be shifted to the consumer, the applications as filed are not financeable without full taxpayer involvement. The only alternative to the comprehensive taxpayer commitment which they espouse, therefore, is no project. It is found, however, that the project is in the public interest and that cooperation between the Commission in formulating tariffs and Treasury in reducing consumer costs by assuaging remote creditor fears will accomplish multiple goals. It will bring this gas to market, protect the consumer, and blunt Treasury's argument that the taxpayer should not be burdened because the gas consumer refuses lesser burdens of risk and partially paying for a service in advance.

There is no legal impediment to the Commission shifting additional risk to the consumer. The Commission has the legal authority to adopt alternative rate methodology and is not limited to any single formula or combination of formulas in determining rates of jurisdictional pipeline companies. As stated in F.P.C. v. Hope Natural Gas Co., 320 U.S. 591, 602-603 (1944), the Commission has the authority to make practical judgments in exercising its ratemaking functions, and the justness and reasonableness of rates is to be determined by "the result reached and not the method employed."

1/ Raising money can be costly in the best of times with much preplanning. It can be even more costly when required under pressure and time constraints.

Thus, as long as arbitrary and unreasonable results are not produced, the Commission may employ any formula or combination of formulas it wishes and is free to make "pragmatic adjustments which may be called for by particular circumstances." F.P.C. v. Natural Gas Pipeline Co., 315 U.S. 575, 586 (1941), Permian Basin Area Rate Cases. 390 U.S. 747, 800 (1968). Even the Commission's legal authority to adopt ratemaking procedures which allow jurisdictional pipeline companies to collect a charge on investments related to facilities prior to completion, a recent issue before the Commission, has been unequivocally recognized. See generally Goodman v. Public Service Commission of the District of Columbia, 497 F.2d 661 (D.C. Cir., 1974); supra Order No. 555, Docket No. RM75-13, mimeo p. 7 (November 8, 1976) 1/

None of the arguments opposing either the consumer or the taxpayer as a partner in financing these projects is based upon any asserted legal impediment to the Commission's authority to take such action. In fact, neither Staff in its Brief on Financing Issues, New York, or California cite one Commission or court decision or point to any section of the Natural Gas Act which would limit such action by the Commission. The issues are philosophical and practical and turn on both the propriety and reasonableness of the policy action, not its legality. 2/

There is no denying that a valid argument can be made against any such regulatory rate relief for applicants in these projects on the basis that such relief represents a departure from the Commission's prior philosophy of how best to protect the consumer from unwarranted gas transmission pipeline company depredations. But in the face of the obvious inability of the utilities to shoulder the burdens and the equally obvious fact that this inability is due more to the size of the project and the long lead time than to any attempt to take advantage of the consumer, broad philosophical historical characterizations are of little help. Not one of those voicing opposition on the traditional grounds--that it is inconsistent with past Commission procedures for protecting the consumer-claims that the utilities could perform the

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1/ While this case involves the PSC of D.C., the court specifically stated it was applying FPC precedents.

2/ Additional proposed legislation--except taxpayer involvement which would reduce the cost of financing--is proposed to overcome practical difficulties, not legal restrictions.

financial trick without these innovations. Basically, in fact, all see federal guarantees lurking in the shadows and after discussing the level of difficulties and the lack of producer participation, look to the taxpayer instead of any substantial regulatory change as the source for their "innovative tariff."

At this point, the dispute between Staff *et al.* and Treasury must be aired. Both view this case as the *nose of* the camel, setting the precedent for future projects in the highly capital-intensive energy industry to make identical claims on regulatory "innovations" or public money, respectively. Both are obviously fearful of any scheme which departs from the norm, as each perceives that norm, and have marshalled every argument at their disposal--often on institutional grounds--to protect their constituency from disruption. Thus, whereas the states perceive a class of consumers--whether it be New Yorkers or Californians--to be protected by them and Staff seeks to protect all consumers as well as the Commission's 40-year old regulatory scheme, Treasury too would avoid what it sees as the beginning of a raid on public monies. 1/

While those representing the public disagree on the consumer role, Staff, Treasury and the states join hands in one major respect. None believes the equity holder should be guaranteed a return of equity investment by the consumer or taxpayer, since this would totally distort the usual marketplace determinations first made by the utility industry of what projects are to be proposed. Neither the Commission nor Treasury is in the position to dictate to the marketplace, nor is it likely they would care to tell consumers what fuel they must burn. The entrepreneur's evaluation of alternative investment opportunities is the primary allocator of investment funds and the great inhibitor of most uneconomic schemes. Its use for this purpose dissipates in about the same proportion that the risk to the promoter is reduced. No case has been made here that the risk of moving reasonably priced gas in the field should not be borne by those seeking utility rates of return at or beyond historical levels. Until such time as the sponsors seek only a management fee in lieu of an equity return, it is for them to take the risks that their decisions on the merits of the projects are valid.

1/ Given variously approved advance payments, optional pricing, non-cost oriented rate making etc., it would seem that Staff may be protesting too much.

The cooperation between the Commission and the Treasury referred to and urged above as being in the public interest is not lightly made, and to be effective, will require legislation. It will serve no purpose to argue whether it is best to only have a change in regulatory approach affecting the 40 or so million people living in California, New York and Wisconsin, as against the 100 million people served by the existing or prospective pipeline-shippers or the 220 million persons represented by Treasury. The change in regulatory scheme is a change, no more no less, and the term "change" of itself carries no pejorative connotations. Both Staff and Treasury are right when they say that a shift to the consumer or taxpayer creates some risk of disallocation of resources. But neither is totally frank when it argues that the equities favor only shifting to one and not the other. The final arrangement here must involve both, and neither can shirk its responsibility to work out arrangements which will permit proper financing at reasonable rates.

Debt service protection is required.[1/] No formula could, or should, be sanctioned before the Staff, Treasury, the successful applicant, and other interested parties have fashioned a proposal which accomplishes this end. Clearly, legislation to perfect tracking to the consumer level and to approve Treasury participation is necessary. It will be recommended. Starting only with the premise that (1) there is a need for this natural gas, and (2) no unusual demands for high prices are met for either unattractively located gas supply or relatively low-risk money, shifting a portion of risk for securing this gas supply to the consumer is in the public interest. However, if the risk is shifted, Treasury should be prepared either to sell non-completion or sustained outage insurance or to enter into some other type of arrangement to remove that remote risk which is left for noncompletion or sustained outage. Coming behind a consumer guarantee of debt service and the sponsors' risk of equity capital, this limited contribution would substantially

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1/ While El Paso argues that it is debt service which must be shifted, its original plan in its Brief on Financing and Regulatory Action called for contractual arrangements with shippers to track both debt service and return of equity (p. 7).

reduce the costs of debt capital and might help attract equity.

On shifting or sharing risk, the evidence of record supports the following findings:

1. The natural gas consumer is one of the principal beneficiaries of attaching this new source of natural gas to the existing natural gas transmission pipeline network.

2. Consumer participation in guarantees on capital costs should occur, but only for the debt service represented by all-events tariff.

3. The equity holder should accept the usual risk of equity investment. Compensation for that risk, given the circumstances here, should be at the higher levels of return currently allowed by the Commission. In order to insure that the equity investor is in fact exposed to the risk, it may be necessary to modify the cost-of-service tariff of the transporter to assure that collection of the depreciation charge does not recover equity capital during periods of prolonged continuous outage. 1/ A "grace period," not to exceed 30 days, for example, would be appropriate, after which the opportunity to recover equity capital would not recur until such time as service resumed. To the extent that lost service could be made up by excess deliveries within 1 year, shippers should pay additional charges to reimburse the disallowed equity recovery. Immediate notification to the Commission of any interruption exceeding 1 day's duration should be required. (See generally New York Commission Tariff Br. 7).

4. With the above arrangements in place, the federal government should entertain an insurance or completion guarantee arrangement to facilitate raising project debt capital at a more reasonable cost and thereby reducing the cost of gas to the consumer.

1/ *Pro rata* reduction and elimination of return on equity in case of service reduction and outage is provided by the proposed tariffs and is discussed, *infra*.

J. Prepayment of Return on Equity

This section deals solely with those preoperations charges proposed to ease the regulated shipper-equity holder's cash flow problem caused by having its capital, whether raised in the money markets or internally generated, committed to a long term investment in the transportation project with no return prior to operation of the tariff. 1/ As has already been determined, the equity holder should bear all risks of equity - both the risk of capital loss and the risk of loss of return. The issue here therefore involves various financial arrangements which, if in place, will permit the equity holder only to maintain his cash flow. An assumption here is that all plans require that any prepayment by the consumer for such charges be treated in the nature of a loan with a clear obligation of repayment on the part of the utility. Refund of monies prepaid is necessary regardless of whether the project is an ultimate success or failure if all risk of equity investment are to remain in the equity holder.

One other prefatory comment is in order. The issues raised here are not usual and do not fit the mold of even the "older" forms of consumer prepayment of charges which have surfaced in the last few years. For example, New York, which did comment on these provisions, appears less than comfortable with its own analysis, and seems to have addressed the matter more out of a sense of obligation to review this important subject early than any acceptance that this phase of the proceeding could decide the issues. As elsewhere in finance and tariff matters, New York's reluctance is well founded, and no decision here at this time can possibly do more than indicate to the parties what appears to be the acceptable range of options on this issue.

A number of tariff mechanisms have been advanced, all of which are variations upon the basic concept of including construction work in progress (CWIP) in rate base during construction (as opposed to capitalizing AFUDC during construction and putting it in rate base once operations have begun). What CWIP means is that the consumer, during the construction period, pays the carrying costs on the construction funds whereas under AFUDC the carrying costs are capitalized, tacked on to the construction cost when service begins, and recovered from the consumer over the life of the facilities.

1/ Protection of debt service is discussed supra, Tracking and Consumer v. Taxpayer Guarantees.

The record indicates that the enormity of equity investment required and the length of the construction period involved creates a financial condition in which adoption of traditional ratemaking principles (the pipeline does not earn a return on investment until the plant is in service) could severely restrict, if not preclude, the financing of this project. While some form of pre-operation consumer charge to aid equity financing appears both essential to the viability of the project and in the public interest, the record does not provide sufficient detail to formulate a mechanism in final form. Instead, certain preliminary findings will be made which should form the outline for a more detailed tariff provision which must be analyzed in the second phase of this proceeding.

Perhaps the most active proponent of CWIP-type tariff provisions is Arctic Gas. Its witness Jeter has presented four alternative methods of generating cash flow during construction (248/43, 248-43, 260; AA-145). In addition its witness Brackett has stated that Arctic Gas and all of its sponsors, which includes the pipeline shippers, favor Method 4 (248/43, 266-43, 267). Accordingly, only Method 4, among the 4 alternatives, will be analyzed in any depth. 1/

1/ To provide a better understanding of Method 4, brief descriptions of the other three methods are given (248/43,264-43,265):

Method 1 - Investment of sponsoring pipelines in the project companies is included in each pipeline's rate base so that return and associated taxes on the investment are added to each sponsor's revenue requirements. AFUDC is capitalized. Each sponsor's equity investment is amortized over the project's life (25 years) and project dividends (or partnership distribution) are flowed through to each sponsor's customers.

Method 2 - The equity investment of the project sponsors would be included in each sponsor's rate base during construction thereby generating cash return, but when the project was put in service, each sponsor would remove its equity investment from rate base. Thereafter, each sponsor would retain dividends or partnership distributions from the project companies. The project companies (Alaskan Arctic, Canadian Arctic and Northern Border) would capitalize only the debt interest portion of AFUDC, not the equity portion.

Method 3 - The project companies would not capitalize AFUDC but instead would bill an equivalent amount to the shippers, to be passed through to their customers, during the construction period. The pipeline sponsors would treat their equity investment in the project companies as non-utility investment so as not to be included in rate base, and they would retain the dividends.

Under Method 4 each sponsoring pipeline subject to FPC jurisdiction would annually charge its customers a percentage of its accumulated equity investment in the project companies (Alaskan Arctic, Canadian Arctic and Northern Border), the charge generating enough cash flow to cover the carrying costs of each sponsor's equity investment. A figure of 15% is suggested. The charge would commence upon the first equity investment, would be collected throughout the construction period, and would continue to be collected for up to the first ten years of project operations, although the equity investment to which this percentage is applied would be reduced by at least 10% for each of these first ten years of operations. The sponsors could accelerate this 10% reduction of equity investment so as to stop customer charges sooner than ten operating years. Once the project commences operations, the sponsoring pipelines (shippers) would start refunding to their customers the full amount of the Method 4 charges collected with compound interest (at the Commission rate set under Section 4). The refund period would be set by the Commission, though 20 years is recommended.

1. Arguments of the Parties

Arctic Gas prefers Method 4 over the other mechanisms for several reasons. First, like the other proposals, it provides the needed early cash flow to fund the sponsor's equity investment. Second, Method 4 customer payments are obligated to be refunded with interest, with no need for project company dividend payments, as in Method 1. This very repayment obligation should obviate federal income tax liability upon these customer payments which means that the sponsors need much less revenues from their customers to cover the carrying costs of their project equity investment (248/43,266). 1/ Arctic Gas makes this choice notwithstanding

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1/ Although Arctic Gas asserts that under Method 4 the investing sponsors would not record these customer payments as income due to the repayment obligation, it notes that the sponsors would employ "equity accounting" for their equity investment in the project companies even though the normal 20% minimum equity ownership (represented as imposed by accountants and accepted by the Internal Revenue Service) is unlikely. It would try to circumvent the 20% requirement by arguing that Northern Border would be a partnership and Alaskan and Canadian Arctic corporate joint ventures. Equity accounting is sought so that the sponsors can report Arctic Gas income in the earlier years of operations before dividends are paid. Arctic Gas asks for Commission concurrence with this interpretation of equity accounting.

its own evidence (AA-145) showing Method 4 as reducing total revenue requirements over the life of the project from the base case (no form of CWIP) less than would the other three methods. 1/ It does so because it puts less emphasis upon these absolute revenue requirement reduction figures and more emphasis upon the discount factor needed for Method 4, which is the lowest among the four methods, and upon the fact that Method 4 imposes the lowest revenue requirements during the first four years, when no gas is flowing.

On brief Arctic Gas stresses the need for a tariff provision, preferably Method 4, to provide the cash flow sufficient to meet the carrying costs on the funds raised by the sponsors for their project equity investment. It views this as essential in light of the enormity of both equity investment and also carrying charges thereon 2/ and the four-year interval between equity investment and receipt of project dividend payments.

Reaction to Method 4 is varied. Staff, for example, totally rejects it (or any other CWIP mechanism) on the grounds that it leads to misallocation of resources by preempting the salutory workings of the unobstructed financial market. Staff suggests that more sponsors should participate so as to reduce the equity investment for each sponsor and therefore permit traditional financing. Staff moreover views as critical defects in Method 4 Arctic Gas' untested assumption that consumer payments will be non-taxable and the fact that the other three methods are less costly to the consumer. It concludes that the record shows no benefit

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1/ Arctic Gas calculated the revenue requirements of the U.S. shippers from 1978 through 20007 to be $20,427.7 million when AFUDC is capitalized during construction with no cash flow until the project commences operations. It then calculated the amount each of the four methods would reduce this figure:
Method 1 - $5,876.4 million
Method 2 - $1,184.9 million
Method 3 - $2,050.2 million
Method 4 - $1,113.2 million

2/ Equity investment by U.S. sponsors of some $1.35 billion (1975 unescalated dollars) to be made over five years and $500 million in carrying charges over the first seven years.

for present ratepayers from any of these methods, notwithstanding possible benefit for future ratepayers, and that accordingly Arctic Gas has not met the Commission's requirement that CWIP provide equitable treatment of present ratepayers. 1/

While unconvinced of the absolute need for any of Arctic Gas' pre-operation CWIP-type charges, New York is not unalterably opposed to Method 4 assuming, however, certain modifications. New York does see problems inherent in these pre-operation consumer charge proposals: an inter-generational transfer occurs, that is, a lack of identity between the present ratepayer paying the charge and the future ratepayer receiving the benefits of reduced capital costs and increased gas supply, the benefits of reduced costs not being realized for over a decade; and such mechanisms, due to the size of the carrying costs involved, prevent an accurate assessment of the economic viability of the overall project, which can only occur when the sponsors have to raise capital in the fianancial market on the merits of the project.

New York urges the Commission to fully explore alternatives to pre-operation consumer charge mechanisms before adopting any such charge. In this vein it suggests deregulating the Alaskan gas project and incremental pricing, increasing the number of equity sponsors, or federal government financial backstopping. If, however, the Commission were to find some form of pre-operation charge an essential tariff provision in order to permit equity financing by the project sponsors, New York would attach several limitations to Method 4 to make it acceptable: the consumer surcharge should terminate when the project commences operations, not after ten years of operations, and the sponsors should then look to project dividends for cash flow; a proper charge be set by the Commission (the implication is that 15% is too high); repayment of the charge with interest by the sponsors to their customers should be accomplished over less than twenty years; the refund interest rate should be more than the suggested 9%, more like 12% to 15%; and the favorable tax ruling on the consumer charge must first be secured.

The other applicants neither made evidentiary presentations concerning CWIP nor responded definitively to the Arctic Gas proposals. In fact El Paso, except for possible inferences to be drawn from its Investment Recovery charge proposal, ignores the

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1/ Inclusion of Construction Work in Progress in Rate Base, Order No. 555, Docket No. RM75-13, issued November 8, 1976 (slip op. at 8), supra.

entire subject, although on brief Alcan concurs with Arctic Gas that some pre-operation consumer charge is essential if the shipper-sponsors are to raise the funds needed for their equity investment. It seeks Commission approval of allowing cash flow to cover the carrying costs of the equity, but it urges deferral of any ruling on specific proposals at this juncture. In addition it challenges Arctic Gas' assumption that the sponsors would qualify for equity accounting of the project companies' income as their own, because they will not meet the 20% minimum ownership requirement for equity accounting.

The Department of the Treasury (250/43,615) proposes rate base treatment during construction of at least equity related if not all CWIP, in order to attract equity capital even when return of and on equity would not be guaranteed upon non-completion. Treasury specifically suggests a consumer surcharge paid by the shippers' customers which would finance a portion of the construction. Once gas begins to flow, these contributing customers would have their contribution, with interest, returned through a credit to their cost of gas. Treasury envisions benefits accruing to the consumers for their surcharge contributions: project lenders and investors would earn a lower rate of return because the surcharge would reduce financial risk.

2. Discussion

The equity investment by the sponsoring shippers - - 25% of all project capital requirements under the current 25% equity ratio advanced by the applicants (but 35% for the ships by El Paso) -- must be raised by those pipelines outside the purview of project financing. Each pipeline must raise its share of this enormous amount of capital on the basis of its own credit standing and incorporate this capital into its own capital structure. Just as the financial wherewithal of these shippers to guarantee the project debt is nonexistent, it also appears that they do not have the ability to raise equity funds absent the generation of cash flow during the construction stage. See, supra, Creditworthy Party sections. Only a consumer prepayment of carrying costs would appear likely to permit raising this amount of equity money.

The Commission recently addressed CWIP in its rulemaking pronouncement, Order No. 555, supra. It held there that "it will not adhere to an absolute rule that plant must be 'used and useful' in the traditional sense before it may be included in rate base." (Id., slip op. at 7). While the Commission then excluded interstate gas pipelines from the limited inclusion of CWIP in rate base, analysis of the reasons stated for that exclusion show that none of the 5 reasons cited apply to the Alaskan gas transportation proposals. The Commission found: (1) CWIP is only a very small percentage (3%) of pipeline gas plant in service. That is obviously not true for the pipeline shippers who sponsor this project; (2) The really huge pipeline projects would most likely employ project financing, which could be thwarted by rate base treatment of CWIP. Some form of CWIP is, however, compatible with the instant project for, as has already been determined, the equity investment will be raised in the first instance basically outside project financing; (3) Gas curtailment obscures the identity between present and future ratepayers. In light of current levels of curtailment, there should be substantial identity between present and future ratepayers affected by this project because high priority requirements will constitute most interstate gas sales when the surcharge commences, and this Alaskan gas is destined for those same high end-use priority customers; (4) The costs and benefits of CWIP would be mismatched by incremental pricing. Rolled-in pricing has already been approved for this project;and (5) The basic problem faced by the pipelines is supply shortages, not transmission capacity. (Id. slip.op. at 8)

The gravamen of CWIP inclusion in rate base is "a judgement that it is equitable for present ratepayers to provide funds that would otherwise be provided by future ratepayers."1/ Id. slip.op., 8. As will be discussed below, such equitable treatment is consistent with a properly designed pre-operations consumer surcharge for this project.

Benefits flowing from a surcharge for equity returns inure not only to future ratepayers but also to present ratepayers, the most obvious benefit being assurance of continued gas supplies. This incremental increase in interstate gas supply is a self-evident benefit as to future ratepayers, and, since the Alaskan gas should begin to flow within four years of the commencement of construction, the class of future ratepayers should not be much different from present ratepayers. The problem of intergenerational transfer, which apparently caused the Commission to limit its Order 555 to certain types of electric utility construction (pollution control facilities and conversions of generating plants to alternate fuels) is small in the instant case because Alaskan gas should flow within four years of the first surcharge payments.

1/ Future ratepayers might well ask whether it was equitable for present ratepayers to undercharge themselves for energy and reduce future availability.

Another benefit is a lower rate of return on project equity which should flow from the reduction in burdens on the utilities overall capital structures.1/ Debt costs might also be lowered because the resulting cash flow should assure adequate supplies of equity capital, which in turn acts to secure the financial viability of the project vis-a-vis the lenders. A related benefit, as already demonstrated in AA-145, is the diminution of the AFUDC account to enter rate base upon the project being placed in service, which means that the project will have a smaller revenue requirement over the life of the project than it would if no CWIP entered rate base during the construction phase.

The need for some tariff mechanism to generate cash flow to finance equity investment has been established. No attempt will be made at this point in the case to choose from among those methods discussed in the record, or to fashion a more acceptable method. Method 4 proposed by the Arctic Gas sponsors may well constitute the basic guide for crafting an appropriate provision.

1/ Certain sensitivity studies were made by computer to evaluate the effect of alternate rates of return on equity on both the proposed Arctic Gas system and on El Paso's ships:

a) A change of one percentage point changes the cost of service correspondingly for two selected years as follows (in millions):

	1982	1985
Alaskan Arctic	$ 6.4	$ 6.6
Canadian Arctic	48.1	65.1
Northern Border	6.2	7.0
Total	$ 60.7	$ 78.7

It should be observed that this does not reflect the western facilities of PGT, nor any other facilities.

b) If the revenue requirements for El Paso's LNG carriers were reduced to reflect a DCF rate of return of 15 percent instead of 17 percent, the unit cost would decrease from $1.78 (EP-228; 88/13,344) to $1.75 or 1.7 percent, based on the computer program available to the Presiding Judge.

K. Tariff

This section supplements the Financing Section, above, and addresses several issues which have arisen concerning provisions contained in the tariffs of the various project sponsors. Discussion will be brief in recognition of the fact that, upon receipt of requisite Presidential and Congressional approvals, the successful applicant must present its tariffs to this Commission for further review.

1. Penalty for Failure to Perform Contractual Service Obligations

There is a substantial issue, essentially between all of the major applicants on one side and Staff and supporting state utilities commissions on the other, involving the calculation of the penalty to be assessed against the transporter in the event of failure to perform the contracted service.

Each of the major applicants has recommended the inclusion of a provision in its tariff which would deny it a full return on equity investment and associated income taxes for service performed for a given shipper, if the transporter accepts from the shipper in any billing month a volume of gas less than 80% of the quantity of gas tendered by the shipper pursuant to the shipper's transportation service agreement.1/ Thus, if the level of service fell to 85% of volumes tendered, no penalty would result; but if the level fell to 75%, the transporter would fail to collect 25% of the otherwise chargeable return on equity and income taxes. In either event, the shipper would be permitted make-up transportation in subsequent billing months; if the monthly receipt deficiency were such as not to trigger the penalty provision (i.e., less than 20%), the make-up transportation would be performed at a reduced charge if a charge were applicable at all.

Staff, however, urges that the penalty provision be amended to require the proposed *pro rata* reduction in return on equity and taxes to be effective for performance at any level less than full volumes tendered within the contract quantity, i.e., it would substitute 100% for the applicants' proposed 80%.2/

The general form of the penalty provision appears to have its genesis in the decisions issued in the El Paso and Transwestern coal gasification cases.3/ In those cases, it was decided that

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1/ El Paso Alaska, Western LNG, Alcan, Alaskan Arctic and Northern Border.

2/ The reference level for both Staff and applicants is the volume actually tendered and not the contract volume which the shipper is entitled to tender, which may be higher.

3/ *El Paso Natural Gas Co.*, Docket No. CP73-131, Initial Decision issued June 21, 1974; *Transwestern Pipeline Co.*, Opinion No. 728-A issued November 21, 1975.

a sliding-scale reduction in equity return and related taxes should be imposed if the plant load factor fell below 75%. However, those cases involved a proposed catalytic methanation of low-Btu gas, a technology not yet proven on a large commercial scale. As Staff correctly points out, there is no such novel technology involved in the proposed large-volume natural gas transportation services at issue here. Staff likens these services to those routinely performed by natural gas pipeline companies under cost-of-service tariffs and points particularly to that service currently performed by PGT, whose existing cost-of-service tariff contains the 100% provision (Staff Ans. Tariff Br., p. 15-17).

Finding nothing novel in the nature of the services here proposed, Staff sees no justification for relieving the transporter of the duty of rendering full service within the contract or paying the penalty for failing to do so. There is, in Staff's view, no reason to grant the service company "a 20% cushion for non-performance;" further, Staff fears that the service company would, under the applicants' proposal, be permitted to discriminate between shippers by serving some at the 100% level and others at something less than 100% (but more than 80%) without incurring a penalty.

The applicants' principal objections to the Staff recommendation are grounded in alleged legal and financial as well as alleged operational considerations. Thus, El Paso, for example, avers that it is entitled under the Constitution to the opportunity to earn a return on its property commensurate with returns earned by other businesses of comparable risk and that the result of Staff's recommendation is immediately to deny El Paso that opportunity if for any reason, including events beyond its control, it cannot accept 100% of the quantities tendered by a shipper during any month. El Paso claims further that adoption of the Staff recommendation would have an adverse, although not fully assessable, impact on its ability to attract equity capital (El Paso Response to Staff Initial Tariff Brief, p. 4). Arctic Gas also states that the Staff proposal would make attraction of equity capital more difficult, and it believes "some tolerance" in the receipt of gas is necessary to permit the recovery of normal charges for relatively minor outages. The 80% figure, it says, simply recognizes the possibility "that sometimes there can be difficulty in fulfilling full receipt or delivery obligations," while the Staff's 100% figure provides no tolerance at all.

El Paso has made no attempt to demonstrate that the protection it seeks is necessary to place it on equal footing with other enterprises experiencing comparable risks. Furthermore, while there is no quarrel with El Paso's proposition that a regulatory agency may not deny the regulated utility a reasonable opportunity to earn a fair return on invested capital, there is certainly no constitutional requirement that the agency endorse rates which insulate stockholders from normal business risk 1/ at the expense of consumers for whose benefit the Natural Gas Act was framed. 2/ Accordingly, there is no legal impediment to adopting Staff's recommendation if the relevant public interest considerations so warrant.

It is clear, moreover, that a provision which would permit full collection of equity-related charges in any month when so much as one-fifth of the promised service is unavailable cannot be justified on the basis of vague references to possible "minor" outages or "normal" fluctuations in transportation capability. The designs of the proposed pipeline transportation systems are not likely to be so finely tuned that they cannot accommodate normal day-to-day operational fluctuations, and there has been no explanation given of the nature and frequency of minor outages occurring on existing pipeline systems which would support the need here for so substantial a cushion for nonperformance. This is true even with the proposed make-up provision. However, with El Paso, which avoided any mention of operational considerations in its criticism of Staff, the problem may be more significant. Its multimode transportation system 3/ is presently designed with much less operating flexibility than is typical of an all-pipeline system, and its cost of achieving comparable flexibility could be substantial. (See Construction section, supra.) 4/

Furthermore, none of the parties has addressed the possible penalties which a shipper might face under its purchase contract with the producer if it failed to take scheduled delivery because of substantial nonperformance by the transportation system.

1/ Lynchburg Gas Co. v. F.P.C, 336 F.2d 942,949 (D.C. Cir., 1964)

2/ Atlantic Refining Co. v. P.S.C. of New York, 360 U.S. 377,388 (1959)

3/ Pipeline to liquefaction facilities to LNG storage to LNG tankers to LNG storage to regasification facilities to pipeline.

4/ With its present design, the El Paso make-up provision could well prove to be largely illusory, in that there is considerable doubt that its shipping capacity will be adequate to accommodate significant make-up transportation.

Although such purchase contracts remain to be negotiated and submitted to the Commission, all are aware that the Prudhoe Bay field is an oil field, that the rate of gas production will be dictated primarily by oil production considerations, and that gas once produced cannot be reinjected without cost.

In these circumstances, it is very much in the public interest to encourage the fullest reasonable measure of timely transportation performance while at the same time giving appropriate recognition to temporary operational difficulties which could occur near the end of a billing month. A good portion of each of the proposed transportation systems will be operated under arctic conditions in remote areas where an outage--no matter how unlikely--could delay service restoration.

Accordingly, it is concluded that the proposed penalty provision should be amended to provide that performance in any billing month at a level not below 90% will not result in penalty, provided further that if make-up transportation for any month's deficiency for which no penalty was assessed is not accomplished within 1 year of the date first requested by the shipper, the transporter shall promptly give the shipper the otherwise appropriate rate credit and interest.

There is nothing in the plain language of the penalty provision as proposed by the applicants, or as here modified, which would permit the possible discriminatory treatment between shippers feared by Staff. Nor is it to be presumed that any applicant would be motivated to apply the provision in a patently illegal manner. Any such willful discrimination would hardly go unnoticed by the shipper suffering it, or by the Commission, which could swiftly remedy the situation (Natural Gas Act, §5(a), 20(a) and 21).

One final point. Both the Arctic Gas and the Alcan tariffs provide for abatement of all charges to a shipper who willfully refuses to perform the promised service; the El Paso tariff and briefs are silent on this point. There is no valid reason for omitting such a provision from any tariff to be approved in these proceedings. El Paso's tariff would require amendment.

2. Auditing, Accounting, and Review

Staff, both on brief and on the record (142/22, 901-22, 902), seeks a certificate condition establishing an audit of the successful applicant's books during construction in order to insure that these tremendous construction costs are prudently incurred and properly recorded pursuant to the Commission's Uniform System of Accounts. Staff feels that such an audit is especially necessary in light of the proposed cost of service tariff, in which the rate paid is primarily governed by entries consistent with the Uniform System of Accounts. All applicants concurred with Staff on the record. Both the record and common sense require a certificate condition requiring a Commission audit of construction expenditures as incurred.1/ This entails on-site inspection and complete access to all the books of the project company. The Commission should provide the details for such an audit procedure.

El Paso, under its Investment Recovery Charge proposal, supra, argues that the results of the audit should be immediate approval of those construction expenditures, with the carrying costs flowed through immediately by the pipeline shippers to the consumer. Treasury supports this proposal as necessary (250/43,618). All costs approved would be final and not subject to later disallowance except for fraud. As discussed supra, this procedure gives a high degree of regulatory certainty without compromising the Commission's review process. The audit reports should be approved on a periodic and current basis, such as quarterly audits which would then be acted upon by the Commission within 90 or 120 days. The Commission ruling would permanently establish whether such costs would be permitted to be recovered through the tariff. In sum, the project company would not be left in doubt until project completion whether it would be permitted to recover all of its costs, rapid resolution of the audit process would better afford the project company an opportunity to prospectively correct accounting or procurement error, thus minimizing the chances for disallowed construction costs, and the gas consumer would be protected from excessive and unnecessary costs.

1/ If the Alaska Natural Gas Transportation Act of 1976 is in effect, a question is raised as to whether a joint FPC effort with the board or inspector of construction appointed pursuant to that statute would be in order.

One of Staff's arguments against these proposals is that the Commission would lose the power to review costs before they went into the pipeline's rates. The applicants argue that the sponsors would be bankrupt if the Commission failed, just once, to act expeditiously to flow through costs. There is a middle way; removal of the right to suspend costs but leave viable the Commission's right to review and order refunds if costs are included which are subsequently found to be unjust and unreasonable. It will be suggested as part of the legislative section, <u>infra</u>.

3. Other Tariff Matters

a. Billing Commencement Date

The tariffs of the transmission companies which make up the Arctic Gas and Alcan groups provide that each company can begin billing as soon as its facilities are in place, regardless of whether service is actually rendered.1/

Under this arrangement, Alaskan Arctic or Alcan, having completed construction, could begin billing U.S. shippers even though it may be prevented from transporting gas in interstate commerce because downstream (Canadian) facilities are incapable of transporting Alaskan gas. Similarly, Canadian Arctic or any of the Canadian components of the Alcan project could commence billing U.S. shippers prior to the time the Alaskan facilities are ready for service. The asserted justification for this provision was that lenders would not permit payment of interest charges and return of principal to be deferred indefinitely (investors in Alcan are not necessarily investors in segments of the Alcan project).

The asserted justification would, of course, disappear if debt service can be flowed through prior to operations, supra. In any event, the proposal to place the project tariff's in effect prior to service commencement appears barred by the Natural Gas Act itself. Prior to the commencement of service, these applicants will not be "natural gas companies", as defined in Section 2(6) of that Act. The Commission is not empowered under the Act to give effect to the tariff provisions of other than "natural gas companies."

The project cost-of-service tariffs ultimately submitted to the Federal Power Commission for approval should be conditioned so as to prevent the commencement of billing thereunder until such time as the contemplated contract service can be rendered.

b. Billing on the Basis of Actual or Estimated Costs

Arctic Gas and Northern Border request authorization to use a monthly billing procedure whereunder shippers will pay a base charge computed according to a formula involving an estimated six-month cost of service plus a "surcharge". Staff, by contrast, contends that monthly cost of service can and should be computed on an actual expense basis.

1/ By contrast, the El Paso tariff contemplates that no billing will occur prior to the time when all project components are capable of rendering service (66/10,166).

Arctic Gas, through its witness, Louis Zanoff, admitted that the companies who will be rendering transmission service could bill each month on an actual cost basis (27/4133-4134). He ventured as justification for the estimated cost billing practice the wish of U.S. shippers to know in advance the cost of gas entering their system. This would allow the shippers to use the purchased gas adjustment provisions of their FPC tariffs to flow through these costs to their customers without a general Section 4 filing (27/4,132-4,133). Any subsequently-determined over- or under-collections would be recovered through the surcharge.

Staff views these procedures as unlawful in that rates are not established on a true past and reasonable basis as required under Section 4 of the Natural Gas Act. Use of the surcharge to remedy this asserted impropriety is, in Staff's view, "somewhat illusory." Moreover, Staff references the frequency with which the prospective shippers of Northern Border have sought rate increase in recent years, and refers to Staff witness Beirne's testimony at 142/22,973-974 to show that, following the initial delivery stages, monthly cost fluctuation should be minimal and could be handled through Section 4 general rate filings without impairing the shipper's ability to render adequate service. Finally, Staff again utilizes witness Beirne to demonstrate that the use of estimated costs "unnecessarily complicates certain cost elements of the tariff" (142/22,928). Reference to the cited testimony indicates that witness Beirne was in no way specific as to the nature of these supposed complications.

Neither El Paso nor the Alcan group intends to rely on estimated costs in billing U.S. customers; on the other hand, neither states any strong conviction against use of such procedures.

There is nothing illegal or unfair about the billing procedure proposed by Arctic Gas. In requiring rates to be just and reasonable, the Natural Gas Act essentially mandates that they be cost-based. Use of these six-month estimates and surcharge adjustment affects only the timing of the recovery of the charged rates, and in no way suggests that those rates will not be cost-justified. There is no evidence that use of this timing mechanism will discriminate in favor of one class of customers over another. Despite Staff's observation that, throughout most of the project life, monthly costs should fluctuate only slightly, the shippers apparently feel there is a genuine advantage to billing and being billed according to a method which insures stability over a six-month period. No party has shown adequate justification for rejecting the Arctic Gas procedure. The Staff proposal, of course, would also be acceptable.

c. Interim Rate ("Phasing")

All parties save Alcan agree on the need for some sort of interim rate in the event of a project startup period in which actual deliveries are below design day or anticipated full volumes, the purpose being to avoid charging shippers currently for the full cost of facilities when those facilities are being only partially used. There is substantial disagreement over the methodology to be used in determining that interim rate, however, with Staff and El Paso joining forces against Arctic Gas.

Alcan proposes to commence full cost of service billing at the outset of initial deliveries. As with its proposal to initiate billing prior to commencement of service, Alcan views this as a device to aid in securing project financing since it will serve to expedite the return of principal and interest to investors. Alcan advances several reasons as to why the device is not inequitable. First, Alcan asserts that, if passed along on a rolled-in based by the shippers, the actual increase in shippers rates will be minimal. Next, assuming that initial shippers will be identical, for all intents and purposes, to future shippers, Alcan avers that, by absorbing a large chunk of capital costs in the early years of operation, these shippers will be lowering their unit charges in later years, when Alaskan gas supplies will represent a larger portion of total gas supply. Over the life of the project, the average unit charge will actually be less than if an interim rate policy were adopted, states Alcan. Should the finder of fact disagree with Alcan in these respects, Alcan would support Arctic Gas over Staff and El Paso.

Arctic Gas proposes a "phasing" method whereby, during the build-up period, a shipper will be charged according to his current proportionate use of the ultimate capacity cost.1/ This method would apply only to Northern Border; since Alaskan Arctic does not anticipate adding its plant in stages, no phasing is necessary. As conceived, phasing could span a period of more than four years, although Arctic Gas does not expect complete build-up to take that long.

Staff proposes use of a fixed interim rate, rather than one determined on a current percentage basis. Whereas Arctic Gas would phase gas plant into service following delivery of the first Mcf, Staff would withhold gas plant from service (Account 101)

1/ A portion of depreciation expense and return on rate base on the full plant would thus be deferred.

until after the interim rate period had elapsed. Revenues received during the initial period would then be applied as an offset to gas plant. In effect, Staff would require the gas plant used during the initial period to be carried on the companies' books as though it were construction work in progress. The interim rate period would be one year in duration, unless a state of full operation could be achieved sooner. Staff charges that Arctic Gas' phasing method violates the "used and useful" rule in that it does not link rates with specific facilities actually in service. The effect of this "impropriety," according to Staff, is to unfairly saddle initial shippers with operating costs that should be borne by later shippers and to unfairly require later shippers to subsidize initial shippers insofar as return, depreciation and income tax expenses are concerned.

Apparently unimpressed with Alcan's assumption that initial shippers and future shippers are one and the same, Staff would reject Alcan's proposal to charge initial shippers on a full cost-of-service basis. El Paso has embraced Staff's interim rate concept, including Staff witness Beirne's definition of the term "Date of First Regular Deliveries", as discussed at 142/22, 924-925.

Clearly, the Alcan proposal must be rejected. Such sharp changes in unit cost over the initial years (see Economics section, supra) should be avoided if possible. The interim rate-phasing mechanisms advocated by Staff and Arctic Gas appear equally well-suited to the task of protecting the financial integrity of the successful applicant by insuring adequate cash flow during the start up period of the project. Staff's proposal, however, provides a closer relationship between charges and facilities actually in use, and for that reason is preferable.

Staff's interim-rate proposal is found superior and, where appropriate, should be incorporated into any tariff ultimately approved.

d. Miscellaneous

In the course of these proceedings, Staff proposed a number of minor tariff adjustments in addition to those highlighted in this section and elsewhere in this decision. On the basis of a general appraisal, the conclusion is reached that Staff's adjustments should be made.

XV

POTPOURRI

A. Reliability

1. National Security

The national security implications of the various transportation systems were studied by the Joint Chiefs of Staff for the DOI report to Congress (EP 231, 170-172) and sponsored for the record by Rear Admiral C. Monroe Hart (Vol. 120). It was concluded in that section of the DOI report that defense during war of both the hypothetical trans-Canada pipeline and Alaska-Lng system is equal in risk, and each is vulnerable to sabotage. Staff, the only party to specifically brief this issue, although others make allusions, concluded that national security issues are a "wash" as between the two types of transportation systems.

As the evidence shows, each system has its advantages and disadvantages. El Paso's entire pipeline portion of its system is under U.S. control, and thus defense strategy may be facilitated. 1/ However, El Paso's project tends to concentrate potential targets, like its liquefaction and regasification plants, whose destruction would present major, long-term outage problems. Similarly, both the oil and gas pipelines would be susceptible to concentrated attack or sabotage on the Yukon River Bridge. 2/ Arctic Gas and Alcan, while not concentrating vulnerable facilities at single locations or subjecting their systems to interdiction at sea, suffer somewhat from the length and location of their pipelines. Moreover, these projects must rely on Canadian security forces for defense over much of their pipeline lengths. No evidence was presented here that any project is entitled to a preference on the basis of national security, and none has been given.

1/ Admiral Hart testified that the State of Alaska would bear responsibility for protecting the system in that state (120/14,230). It is assumed that this issue will be resolved before the oil flows and will not be at issue if a gas pipeline is subsequently certificated.

2/ At the same time that concentration of facilities may present a more inviting target, it also increases opportunity for easier protection.

2. Cost Overrun

Several aspects of construction and operation reliability, such as LNG facility interfacing, have been discussed above and will not be repeated here. The degree of reliability is in large measure dependent on probabilities. The best experts' opinions with the best state of the art risk analysis or fault tree cannot overcome the law of probability which says that virtually anything is possible no matter how improbable. On this record, it is difficult to challenge specific ship building costs. The Paul Kaiser (one of El Paso's LNG ships for use in the Algerian-U.S. trade) was built on time at its projected costs. LNG ships also have an enviable safety history. But it is not at all farfetched to say that LNG ships, as ships, can lose rudder control even with two rudders, can have improbable engine failure, even with two engines, or can experience unanticipated and long-term outages having nothing to do with the LNG cargoes. And although El Paso points out correctly that cost overruns did not occur on the Paul Kaiser, one swallow does not a summer make and the shipbuilding industry's general propensity to stay within cost estimates is another matter. Pipeline costs escalate just as well and the fact is that the safest ship is not as safe as a buried pipeline.

A significant aspect of reliability is, of course, the ability to keep the pipelines running. Both El Paso and Alcan have advantages in being close to roads, but this is not the end of the inquiry. Both are also in areas of high seismic risk and difficult terrain. Pipeline problems during the winter in Atigun Pass or Thompson Pass, for example, would be difficult to repair. Moreover, the advantages that El Paso and Alcan enjoy in repair logistics assume that the roads are open in all weather, which may be a poor assumption.[1]

While there is no way of arbitrarily picking what cost overruns might occur, it is not irrational, solely for illustrative purposes, to assume a 20% cost overrun on any of the

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1/ There is also a question of who pays for keeping an Alaskan road, like the haul road, open in all-weather conditions.

projects given the discussion above. 1/ If it is assumed that a 20 percent cost overrun has a 20 percent effect on unit costs, the unit costs become as follows:

Applicant	As Set Forth In Economics Section	Unit Costs Increased By 20%
Arctic Gas	$ 1.60	$ 1.92
El Paso	2.15	2.58
Alcan	1.91	2.29

Interestingly, even at this transmission cost and assuming a rational field price, Arctic Gas is clearly marketable on both an incremental and a rolled-in basis. El Paso is marginally so.

1/ This 20 percent cost overrun assumption represents cost overruns half as great as experienced by Alyeska from October 1974 to the present. (According to Alyeska press releases, Alyeska's October 1974 cost estimate was $5.5 billion, while its current estimate is $7.7 billion, representing cost increases of 40%). It should be noted that the initial $900 million cost estimate for Alyeska detailed a project bearing little resemblance to the pipeline actually constructed. The applicants in the instant proceeding have maintained that they have learned from Alyeska's experience, and already factored many of the oil pipeline's overruns into their own cost estimates.

B. Data Processing

The cost estimates generated in this proceeding could not have been compiled absent the use of computer technology; the parties relied heavily on various computer systems to prepare and detail their projects. The Commission, as is well known in the industry, has been developing computer capability of increasing sophistication. The need for the decision-maker at each level to be able to analyze data generated by the parties in support of their positions does not require any discussion.

Prior to the close of the hearing, therefore, the Presiding Judge recognized the need for a greater ability on the Commission's part to analyze the record on the same basis as was developed by the applicants--a capability which unfortunately was not then in place. 1/ The Presiding Judge pressed the applicants on the record to supply that computer software to the Commission which they used in preparing their cases and they agreed to cooperate. This has had only limited success, not necessarily because of any unwillingness on the part of the applicants to supply material, but because of the limited time available to the Presiding Judge to both put in place and fully comprehend the logic of all the existing programs as well as to develop additional software to replace the numerous hand calculations performed by each applicant. All of the material was not available at the time this Decision was completed, and, except for several discrete analyses made, little of the material garnered was used by the Presiding Judge. 2/

The technology thus acquired and adapted, however, should be of great benefit for the Commission. It is anticipated that all software packaging will be completed for Commission use and it will be calibrated using record evidence of the applicants' base

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1/ In brief, Staff frankly admits that it "has not independently costed out the three systems" (Position Brief p. 18).

2/ All material made available to the Presiding Judge, of course, is available to the public.

cases. Calibration to the various exhibits submitted by the parties **constitutes** the only reliable validation open to the technical staff during the remaining time allotted for the preparation of a Commission analysis.

Acting on behalf of what the Presiding Judge believes the Commission needs and at the risk of being presumptuous, the parties are directed to provide ... the detailed technical aspects of this computer technology to the Commission. 1/ It is absolutely necessary to avoid any additional loss of valuable time that this should be done immediately. The applicants are directed, therefore, to make available all material necessary to provide the Commission with the computer technology required to duplicate all of their cost and financing presentations in this record. To this end, they should provide:

(1) Explanations and work papers of all manual calculations and all computer software;

(2) Engineering studies and computer programs utilized to develop all facility designs and construction estimates, including escalated and unescalated cost data;

(3) All computer data files used to develop the testimony of this record, and any additional files that may be requested for further analysis by the Commission;

(4) All automated or manual calculations utilized to develop allocated delivered costs to lower-48 markets, along with current design specifications and contractual arrangements with regard to delivery volumes at specified delivery points. These directives are not intended to infringe on any contractual committments of any of the parties with third party computer software or hardware companies. Each applicant should keep in mind that a failure to provide all material may result in the inability to expeditiously evaluate its project; and

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1/ Material described here should be made available to the Commission delegates or their designees.

(5) To facilitate these analyses, the Commission should waive the *ex parte* prohibition for selected Commission technical personnel so that they may converse with the parties on the technical nature of the software installations and subsequent changes that can produce results not readily verifiable from the record.

It is hoped that the Commission Staff will publish documentation for each of these models and the Commission will accept no claims of confidentiality or proprietary rights to that documentation so that all work can be put in the public domain.

C. Eminent Domain

A collateral issue has been raised in this proceeding as to the scope of the eminent domain power conferred under Section 7(h) of the Natural Gas Act. Specifically, may the Congressional grant of eminent domain powers be exercised by a person holding a Commission certificate of public convenience and necessity to acquire right-of-way through state lands? Arctic Gas and Staff answer in the affirmative, El Paso and the State of Alaska in the negative. Alaska adds that the issue is moot and therefore should not be addressed, because it would grant all necessary rights-of-way to the successful applicant.

Section 7(h) of the Natural Gas Act provides in pertinent part that:

> /w/hen any holder of a certificate of public convenience and necessity cannot acquire by contract, or is unable to agree with the owner of property to the compensation to be paid for, the necessary right-of-way to construct, operate, and maintain a pipe line or pipe lines for the transportation of natural gas and the necessary land or other property, in addition to right-of-way, for the location of compressor stations, pressure apparatus, or other stations or equipment necessary to the proper operarion of such pipe line or pipe lines, it may acquire the same by the exercise of the right of eminent domain in the district court of the United States for the district in which such property may be located, or in the State courts.

For the reasons given below, the eminent domain grant to persons holding Section 7 certificates applies equally to private and state lands.

It is beyond argument that the federal government has the constitutional power to acquire state property by exercise of eminent domain. 1/ In addition, the federal government can delegate to a private party, such as the recipient of a Section 7 certificate, the power to exercise eminent domain when needed to fulfill the certificate. 2/ At issue now is whether such a delegatee has lesser powers of eminent domain than does the delegator, the federal government.

1/ E.g., U.S. v. Carmack, 329 U.S. 230 (1946); State of Oklahoma v. Guy F. Atkinson Company, 313 U.S. 508 (1941).

2/ Thatcher v. Tennessee Gas Transmission Company, 180 F. 2d 644 (5th Cir.), cert. denied, 340 U.S. 829 (1950).

Turning to Section 7(h) itself, there is nothing on its face to compel a reading of the crucial term "owner of property" to exclude a state. To the contrary, "owner of property," which is not defined in Section 2 of the Natural Gas Act, does not appear to be a term of art, and it is reasonable to include a state within the plain meaning of that term, since states can own land. 1/ Looking behind the statutory language, there is no legislative history that warrants any other reading. The language of Section 7(h) indicates a Congressional grant of plenary eminent domain power to certificate holders, such a grant satisfying the dictum cited by El Paso from U.S. v. Carmack, supra, 329 U.S. at 243, n. 13.

While there are no judicial pronouncements definitively resolving this question vis-a-vis Section 7(h) of the Natural Gas Act, consideration of the analogue and predecessor of this provision under the Federal Power Act, Section 21, is helpful. Section 21 of the Federal Power Act is the model for Section 7(h) of the Natural Gas Act. The corresponding language relevant to this inquiry is identical, and accordingly it is proper to look to judicial decisions interpreting Section 21 to aid in the statutory construction of Section 7(h). 2/ When this is done, it is clear that Congress intended to grant recipients of Section 7 certificates the full powers of eminent domain. Specifically, hydroelectric project licensees under Part I of the Federal Power Act have eminent domain power under Section 21 to condemn state land. 3/

In the present context, it does not appear that a certificate holder would be thwarted by state recalcitrance, since Alaska has stated on brief that it will grant the necessary right-of-way across state land to the successful applicant. Nevertheless, such a question of statutory interpretation should not be left unanswered.

1/ The term must be at least as broad as the term "person," which is statutorily defined and has been held to include state agencies. F.P.C. v. Corporation Commission of Oklahoma, 362 F. Supp. 522; affirmed 415 U.S. 961 (1974).

2/ United Gas Pipe Line Company v. Mobile Gas Service Corporation, 350 U.S. 332 (1956).

3/ City of Takoma v. Taxpayers of Takomà, 357 U.S. 320 (1958); State of Missouri v. Union Electric Light and Power Company 42 F. 2d 692 (W.D. Mo. 1930).

D. Regulation of the El Paso Ships

The absence of direct plenary jurisdiction by any agency of any government over the operations and charges of the El Paso tanker fleet (see Jurisdiction section, supra) constitutes the most obvious and potentially, perhaps, the most serious missing link in regulation of project activities proposed in this proceeding. One need not elaborate on the obvious and substantial adverse impact on the public interest which would result from either subsequent diversion of any or all of the tankers from the El Paso Alaska trade or the fixing by contract of unconscionable shipping rates. Under the 2.4-Bcfd case, the capital cost of the eight-ship fleet is about $1.6 billion or about 25% of the total El Paso project capital cost.

If the El Paso project is to be approved, the protection of the public interest requires that such a regulatory gap over so substantial an enterprise be closed, either indirectly through conditions attached by the Commission to any certificate issued to El Paso Alaska or directly through suitable federal legislation. 1/

Implementation of the first alternative would require, at the very least, that El Paso Alaska (1) bind the shipping companies by contracts acceptable at the outset to the Commission respecting all pricing provisions, including any price changing provisions, and all terms governing continuing dedication of the ships to the service over the project life; (2) be forbidden to agree to any subsequent contract amendments materially affecting the terms of the approved contracts without prior Commission authorization; (3) cause to be made available for Commission audit, both during the construction period and operations, all books and records of the shipping companies; and (4) if it exercises effective corporate control over the shipping companies, be forbidden to divest itself of such control without prior Commission approval. Imposition of such certificate conditions to gain some measure of regulatory scrutiny and review is not unprecedented. 2/ However, use of this regulatory device has been neither fully explored by the Commission nor adequately tested in the courts. In these circumstances, the Commission may wish to recommend appropriate federal legislation to confer jurisdiction in order to avoid the uncertainty.

1/ Under the El Paso proposal, each ship, in all likelihood, would be separately incorporated, and El Paso Alaska would enter into separate transportation contracts with each shipping company. The shipping charges would be made directly to El Paso Alaska and would flow through to shippers under its cost-of-service tariff.

2/ See, e.g., El Paso Natural Gas Company, Docket No. CP73-131, Initial Decision issued June 21, 1974.

E. The Consortium

An interesting argument made by Arctic Gas is that the El Paso proposal would be subject to extraordinary delays because, unlike the Arctic Gas project, El Paso has no consortium of shippers ready and able to go forward as soon as a certificate is issued. Moreover, Arctic Gas muses about how the shippers or the Commission will review an effort by El Paso to recoup its early outlays through a "promotional advantage" (Arctic Gas Summary Br.8).

While it is true that the final group of shippers will not be known until producers' sales contracts are effected, there is little question that most of the pipeline transmission companies involved in this proceeding will be shippers and equity contributors and that they have had almost as much time to look over El Paso's shoulder as they have had for Arctic Gas. Admittedly, some additional time might be lost in the initial stages of putting a consortium together, but this would not significantly exceed the time it will take Arctic Gas to bring all of its participants into the fold.

The question of a possible promotional interest must be addressed. If the shippers presently supporting Arctic Gas make this available by giving El Paso a greater share of equity than El Paso's equity contribution, they would in a sense be charging their consumers for having lost the competitive application. It does not seem probable that a promotional interest of any consequence could be approved between future natural gas companies which would charge consumers disproportionately for supplies from the same source. Regardless, this is clearly one more aspect of the El Paso financial plan which the Commission should look at with great care if its project were approved.

F. Conditions (Environmental)

Environmental conditions have been detailed by Staff for the El Paso project in Staff's Initial Alaska and California Siting Briefs, and for the Arctic Gas, El Paso and Alcan projects in Staff's Initial Environmental Brief. El Paso has responded to Staff's Alaska siting conditions in its own Alaska Siting Reply Brief. Alcan has responded very generally to Staff's conditions in its Rebuttal Environmental Brief.

Arctic Gas has not stated its position on the various Staff conditions. It has maintained that the limited briefing schedule requires that attachment of terms to a certificate be a "Phase 2" activity, and that such a procedure is in fact mandated by the Alaska Natural Gas Transportation Act of 1976. 1/

It is concluded that Phase 2 would be a more appropriate forum in which to decide specific conditions. Findings concerning conditions have been made in the course of this Initial Decision where they have been critical to the issues discussed therein. Any certificate issued to a successful applicant should be consistent with these findings. However, no formal order will be entered now imposing these conditions.

Staff has done a commendable job in formulating conditions as part of its environmental position. These conditions, however, can be more narrowly drawn and focused at a later time when they will pertain to a specific project as certificated by the Commission. For example, Staff suggests conditions be imposed relating only to El Paso's Point Conception siting. Since this Decision has already found Oxnard to be the preferred site, it will be necessary for Staff to draft new conditions applicable to Oxnard, if El Paso is finally certificated. Furthermore, it is the understanding of the Presiding Judge that FPC and DOI environmental consultants have met and will be proposing further environmental stipulations. It will be advantageous to have these suggestions available at the time the Agency prepares its final order on conditions.

1/ Arctic Gas reasons that the Act intends FPC conditions to be issued after the President selects a transportation system and in light of any conditions which the President may make under § 7(a)(6).

The applicants can also benefit from the additional time to continue to study areas of particular environmental concern. More definitive research on the seawater cooling system at the LNG plant or water withdrawal from springs, for example, will be extremely useful in formulating conditions. Of course, the eventual certificate holder will have a better opportunity to analyze and discuss conditions in a later phase of the hearings.

G. Additional Implementation

Any evaluation of the proposed transportation systems must include an appreciation of the time constraints under which any set of sponsors must operate. In earlier sections of this Decision, findings have issued as to the asserted abilities of individual applicants to achieve their contemplated construction schedules. The purpose of this section is simply to identify certain governmental and private prerequisites which will have to be met before construction of any project, once selected, can actually get under way.

1. Governmental

Under the Alaska Natural Gas Transportation Act of 1976, this Commission has until May 1, 1977, to issue its findings and recommendations as to which, if any, of the proposed systems will best serve the public interest of the United States. Presidential action can occur as early as September 1, 1977, or as late as December 1, 1977. Congressional approval, if forthcoming, could follow within 60 days. Thereafter, the successful applicant would have to obtain the necessary basic federal authorizations. These would include final Federal Power Commission certificates, right-of-way permits from the Department of Interior and, in the case of El Paso, permission to construct a marine terminal and LNG plant on federal land. As part of final Commission action, it is now anticipated that "Phase 2" of these hearings will involve examination or reexamination of, inter alia, financial plan feasibility, marketability, tariffs, producers' field production agreements and plans for gas treatment plants, and tariff and environmental conditions.1/

Selection of a construction start-up date also presupposes the receipt of necessary approvals from the various states whose lands will be crossed by the selected project. It is unrealistic to assume that final project financing can be obtained before all such authorizations are in hand. With the possible exception of California (should El Paso, with its LNG regasification plant component, be chosen), no state has indicated any genuine unwillingness to accommodate the proposed projects. Alaska, the key state, has stated on the record it would cooperate with any successful applicant. Accordingly, it is expected that negotiations between the project sponsors and the affected states can and will be satisfactorily completed by the time basic federal authorizations are secured.

1/ See El Paso's Regulatory Action Brief, pp. 8-11, for an exhaustive list of necessary preliminary activities and agreements.

A final prerequisite to commencement of an Arctic Gas or Alcan project is the receipt of necessary permits from Canadian governmental authorities. These matters have been extensively treated in the Canadian Law section (and appendix) of this Decision. As found therein, definitive and specific action by the Canadian NEB should precede issuance of basic federal authorizations by this government to any trans-Canadian proposal.

2. Private

Of paramount importance, and common to all projects, is the need for execution of gas purchase contracts between the producers of Alaskan gas and the prospective shippers. Absent legislative intervention, such contracts will of course become operative only upon approval by the Federal Power Commission. As discussed supra, efforts by the Presiding Judge to secure pledges from the producers as to when such contracts might be concluded turned out to be an exercise in futility.

3. Logistics

One set of potential pre-construction logistics difficulties which was widely discussed on the record during the first part of the case, but which was not pressed on briefs, is the time required for the ordering and delivery of construction materials. Because of the long lead times necessary for ordering pipe, superditchers, snow-making machines, etc., an Executive order or similar agency proclamation giving procurement priority and allocation support to the certificated project may be necessary. In the case of Alyeska, the General Services Administration and Federal Energy Administration jointly promulgated orders granting priority assistance for certain items on the line, pump stations and terminal, 39 F.R. 34608 (1974), for fabrication of modules for North Slope development, 40 F.R. 26 (1975), for further priorities on the North Slope, 40 F.R. 5409 (1975), and for construction machinery and equipment, 40 F.R. 19238 (1975). Similar measures may be necessary in this case to assure timely delivery of natural gas to the lower-48 states.

H. DOI Report to Congress

A document which has proved of inestimable value in the management of the proceeding, as well as in refining the issues, is the report to the Congress (pursuant to Public Law 93-153) issued by the DOI in December 1975 - styled Alaskan Natural Gas Transportation Systems (EP-231)("Green Book"). This 250 page document examines or touches upon most of the issues which must be resolved in this case. Its use has enabled the parties, as their best interests dictated, to direct their attention to the weaknesses in their own cases or that of their competitors, and a major portion of the document ultimately was supported by witnesses and admitted in evidence. Much of the material contained in the Green Book was subsequently augmented or supplemented by specific testimony. Nevertheless, the report is an excellent primer on the gamut of issues confronting the fact finders and policymakers.

XVI

PROPOSED LEGISLATION

A. Section 13 of the Alaska Natural Gas Act of 1976

The State of Alaska has entered into contracts for the interstate sale of its royalty gas which include provisions permitting the State to subsequently withdraw the gas from the interstate market for use within the State. These withdrawal provisions are sanctioned by Section 13(b) of the Alaska Natural Gas Act of 1976.

However, as discussed in the Jurisdiction and Financing sections of this Initial Decision, substantial difficulties arise from the State's asserted right to commit its gas to interstate use with one hand and take it back with the other. The mere prospect of withdrawal imperils the financeability of an Alaskan gas project; actual withdrawal would idle downstream facilities and in turn produce adverse cost impacts.

Moreover, when the Section 13(b) withdrawal provision is coupled with the Act's "equal access" provision, 1/ it becomes readily apparent that the statute in its present form could operate to confer a substantial indirect subsidy to the State. Assuming that the project could be financed and completed, that Alaska's interstate customers (El Paso Natural, Tenneco Alaskan, and Southern) participated in the equity financing with consumer guarantees, and that Alaska thereafter found an intrastate use for its royalty gas, the consumers of the three customer companies would have risked their dollars to help finance the project, only to see consumers in Alaska reap the reward.

For the reasons stated herein, the Presiding Judge respectfully suggests that the Commission, in its recommendation to the President, give consideration to the desirability of amending the Alaska Natural Gas Act of 1976 to delete therefrom Sections 13(a) and 13(b). Absent deletions of these two provisions, direct and total U.S. government guarantees would appear to be the only feasible method of financing.

1/ Section 13(a) of the 1976 Alaska Natural Gas Act would deny the Commission the power to limit access to the transportation system to shippers participating fairly in its equity financing. It is questionable whether the proposal to finance an Alaskan project with consumer guarantees is possible in the face of this statutory provision.

B. Other

Unlike the preceding extended discussion respecting Section 13 of the Alaska Natural Gas Transportation Act of 1976, the need for the following legislative recommendations has been adequately addressed in the Financing and Potpourri sections, supra:

1. LNG Ships

To insure effective regulatory control of rates and operations of the El Paso tanker fleet, explicit statutory jurisdiction should be conferred on the Commission.

2. Tracking

Full and timely recovery from ultimate consumers of all appropriate costs in connection with an Alaskan transportation project, during both the construction and operations periods, requires implementation by Federal legislation. The Commission should not have the power to suspend such flow through of costs, but the right to review all such costs at all times, with the power to order refunds where appropriate, should be **preserved.**

3. Federal Financial Participation

The Treasury Department should be granted statutory authority necessary and appropriate to accomplish whatever Federal participation in the Alaska gas project financing is ultimately determined to be required in the public interest.

XVII

SUMMARY

The extensive discussions above give some of the flavor of the public debate now underway as to which pipeline applicant should be certificated and what degree of consumer or taxpayer involvement is warranted. The full measure of interest and controversy also was displayed in the plethora of Wrap-up Briefs and Position Briefs filed by all the applicants (including affiliates), intervening states, natural gas transmission companies, distribution companies, Conservation Intervenors and Staff.

As has been stated supra, Staff, charged directly with representing the public interest, supports the Arctic Gas project (without the western leg) as vastly superior. The Conservation Intervenors support Alcan, on environmental grounds. Of those states which support a particular project in their Final Briefs, the majority choose Arctic Gas. New York, Wisconsin and California voice support for the Arctic Gas system. 1/ It is significant, in fact, that the most populous states in the east and west, and one of the largest in the midwest all see their interests best served by the Arctic Gas project, if any Alaskan gas delivery system is built. California's preference is predicated in part not on the economics of these proposals, which it finds marginal, but on the ability of Arctic Gas to move the additional supplies it expects to come from the far north. Alaska is the only state which supports El Paso, based on the perceived environmental, socio-economic and reliability benefits. Interestingly, Washington and Oregon do not state a preference for any project, but, like California, state their support for Arctic Gas with a western leg (if Arctic Gas is certificated). Utah supports an overland route with a western leg. Arizona, while not preferring any system, wants assurances that it will have direct access to, and an equitable share of, Alaskan gas. This argument seeking to allocate gas supplies is premature in that no producer sales contracts have been entered.

Of those gas transmission and distribution companies which support a particular project, the majority choose Arctic Gas. Algonquin Gas Transmission Company (New England), Michigan Consolidated Gas Company (Michigan), Wisconsin Gas Company (Wisconsin) and

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1/ The State of Wisconsin petitioned to intervene in January, 1977, and the Commission approved intervention by order dated January 25, 1977.

the New York Gas Group (New York) favor Arctic Gas. Intermountain Gas Company (Idaho) supports Alcan, on the basis of environment and reliability. Tennessee Gas Pipeline Company and Southern Natural Gas Co. prefer El Paso, but their views can be given little weight. As is conceded in the briefs, these companies have signed agreements with Alaska to purchase royalty gas, and thus were contractually bound by Alaska to support El Paso. Cascade Natural Gas Corporation (Washington and Oregon) and Washington Water Power Company (Washington) only voice their support for a western leg and, of course, all of the many major transmission and distribution companies sponsoring Arctic Gas support their project.

In a sense, there is a consensus on the part of the Commission Staff, the most popular consuming states taking an active interest, and an array of pipelines and distributors serving huge sections of the country that if any pipeline applicant must be chosen now, their best interests would be served by choosing Arctic Gas. The evidence in this record clearly supports that conclusion. There is no need to summarize here the findings made in the individual sections above. The Arctic Gas application is superior in almost every significant aspect when compared to El Paso. Certification of its proposal, subject to appropriate conditions, will bring more energy to market cheaper and more reliably than El Paso and will do so in an environmentally acceptable manner. It is found that Arctic Gas' prime route should be certificated, including both western and eastern legs.

El Paso, too, has a viable plan which technically can be built in an environmentally sound manner and which can deliver natural gas to all U.S. markets. While its certification is less desirable because of the reasons discussed above, nonetheless, it could be certificated if it were not for the clearly superior Arctic Gas application. Thus, if Arctic Gas is unable to accept a certificate, this record supports findings that El Paso's proposal, as required to be modified by the findings above, would also meet the present and future public convenience and necessity.

No finding from this record supports even the possibility that a grant of authority to Alcan can be made. No grant could include Westcoast, but its sponsors state that exclusion of Westcoast would render Alcan's financial plan inoperative. The allocation procedures supported in the record by AGTL are now inoperative according to AGTL, and this means no meaningful costing of facilities can be made from this record. Furthermore, Alcan's present design is clearly neither efficient nor economic since the pipeline is undersized. The suggested three years construction schedule to be completed by 1981, which Alcan argues is one of its prime strengths, cannot occur. Moreover, its arguments as to how it can be financed in separate time frames from Maple Leaf, also critical to its proposal, requires intricate timing that is totally unsupported by hard evidence. As presently proposed, even with Alcan's willingness to build anything anyone wants (as long as it does not oust Westcoast and AGTL from their Maple Leaf project), there is not enough left of its original proposal to serve as a basis for granting its application.

Nahum Litt

Nahum Litt
Presiding Administrative Law Judge