CERTIFICATE, ANGTS IMPORTATION; FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND AUTHORIZING THE IMPORTATION OF NATURAL GAS

CERTIFICATE ANGTS
IMPORTATION

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Charles B. Curtis, Chairman;
Georgiana Sheldon, Matthew Holden, Jr.,
and George R. Hall.

Northwest Alaskan Pipeline Company	Docket Nos. CP78-123, et al.
Northern Border Pipeline Company	Docket No. CP78-124
Northwest Pipeline Corporation	Docket No. CP79-56
El Paso Natural Gas Company	Docket No. CP79-57
Pacific Interstate Transmission Company	Docket No. CP79-58
Northwest Alaskan Pipeline Company	Docket No. CP79-59
Pacific Gas Transmission Company	Docket No. CP79-60
Northwest Alaskan Pipeline Company	Docket No. CP79-170
Northern Natural Gas Company	Docket No. CP79-396
ANB Gas Company	Docket No. CP79-399
United Gas Pipe Line Company	Docket No. CP79-400
Panhandle Eastern Pipe Line Company	Docket No. CP79-403

FINDINGS AND ORDER ISSUING CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND AUTHORIZING THE IMPORTATION OF NATURAL GAS

(Issued April 28, 1980)

CONTENTS

I. BACKGROUND

These proceedings involve applications for import authorization and related applications for the construction of necessary facilities and for the sale and transportation of imported volumes of natural gas from Alberta, Canada, through "pre-built" facilities of the Alaska Natural Gas Transportation System (ANGTS). 1/ The ANGTS is designed to transport natural gas from the North Slope of Alaska to the lower 48 states. The pipeline will be constructed through Canada, and will separate into two legs (Western and Eastern) just north of Calgary. The Western Leg will enter the United States near Kingsgate, British Columbia and terminate at Antioch, California. The Eastern Leg will enter the United States near Monchy, Saskatchewan and terminate at Dwight, Illinois. The applications here involve the early construction of a portion of both the Western and Eastern Legs of the ANGTS to import 1.04 Bcf per day of Albertan gas. 2/ The proposed facilities would be constructed prior to the time final governmental authorization and financing have been obtained for the remaining portions of the ANGTS necessary to carry Alaskan gas. The remaining ANGTS facilities would be constructed and placed into operation after construction of the "prebuilt" portion, at which time both Canadian and Alaskan gas would be transported through the completed ANGTS.

1/ The Commission's authority to consider the import applications devolves from Department of Energy Delegation Order No. 0204-8 (42 F.R. 61491).

2/ Northwest Alaskan Pipeline Company (Northwest Alaskan) proposed to import 240,000 Mcf of gas per day at Kingsgate, British Columbia for resale to Pacific Interstate Transmission Company (PIT), and in another application proposed to import 800,000 Mcf of gas per day near Monchy, Saskatchewan for resale to United Gas Pipe Line Company (United), Northern Natural Gas Company (Northern Natural), and Panhandle Eastern Pipeline Company (Panhandle). Underlying the import applications are two gas sales contracts between Northwest Alaskan and Pan-Alberta Gas, Ltd. (Pan-Alberta).

By order issued April 20, 1979, the Commission consolidated all of the prebuild applications for hearing and divided the hearing into three phases. 3/ Phase I was designed to examine the relationship between the prebuild project and the implementation of the ANGTS; Phase II to examine generally the merits of the prebuild project; and Phase III to evaluate proposals to import Canadian gas which may be competitive with the prebuild proposal. The April 20 order waived the intermediate decision procedure for Phase I. By order issued November 30, 1979, the requirement of an intermediate decision for the remaining phases of this proceeding was waived.

On September 6, 1979, the Commission issued an order establishing special procedures for considering cost estimates for the proposed prebuild facilities. Finance Condition No. 2 in the President's Decision 4/ requires that, as part of the final certification of the ANGTS, the cost estimates filed with the Commission be reviewed to determine if they "... materially and unreasonably exceed comparable estimates filed by Alcan 5/ with the Federal Power Commission on March 8, 1977..." The requirement for an intermediate decision with respect to these matters was also waived.

3/ The applications of Northern Natural, Panhandle, United, and ANB Gas Company (ANB) were not consolidated by that order. Those applications were consolidated by the Commission's order in this proceeding issued January 11, 1980 (hereinafter referred to as the Western Leg order).

4/ Decision and Report to Congress on the Alaska Natural Gas Transportation System, Executive Office of the President, Energy Policy and Planning (September 1977), (hereinafter cited as Decision).

5/ The President's Decision, p. 4, designated the Alcan pipeline Company to construct the segment of the ANGTS within Alaska. Northwest Alaskan is the successor in interest to Alcan.

The Commission conducted a separate hearing in this proceeding on the Phase I issues. Direct testimony in Phase I was submitted by certain of the sponsors, and the trial staff filed answering testimony. Initial and reply briefs were submitted by the sponsors 6/ and the staff. In addition, the State of California and the California Public Utilities Commission (California) and the New York Public Service Commission (New York) filed initial and reply briefs. The State of Michigan and the Michigan Public Service Commission (Michigan) also filed a reply brief.

Phase II of this proceeding considered the general issue of whether the proposed imports meet the standards of Section 3 of the Natural Gas Act. This phase was subdivided by the presiding judge into a Phase II-A and a Phase II-B. 7/ Phase II-A addressed issues such as the Northern Border Partnership Agreement, gas supply and the underlying gas contracts, and the exchange arrangements among the shippers, as well as the issues pertaining to the Western Leg prebuild project. The project sponsors and the staff filed evidence in Phase II-A.

Phase II-B related solely to the Eastern Leg and involved such issues as Northern Border's financing plan and cost estimates. All rate of return and tariff matters pertaining to the Eastern Leg, except for depreciation and shipper tracking, were addressed by the Commission's incentive rate of return rulemaking in Docket No. RM78-12. 8/

6/ Separate initial briefs were submitted by Northwest Alaskan, Northern Border and Northern Border Shippers (Northern Natural, Panhandle, and United), Western delivery sponsors (PGT, Northwest, and PIT), Foothills Pipelines (Yukon) Ltd. (Foothills) and Pan-Alberta, and El Paso. The U.S. sponsors (Northwest Alaskan, Northern Natural, Panhandle, United, Northwest and PIT) filed a joint reply brief.

7/ Report of Acting Chief Judge on the Procedural Schedule for Phases II and III (May 8, 1979).

8/ Order No. 31, "Order Setting Values for Incentive Rate of Return, Establishing Inflation Adjustment and Change in Scope Procedures, and Determining Applicable Tariff Provisions", issued June 8, 1979, and Order No. 31-B," Determination of Incentive Rate of Return, Tariff and Related Issues" issued September 6, 1979.

The April 20 order also established Phase III, to evaluate proposals to import Canadian gas which may be competitive with the sponsors' prebuilding proposals. Testimony was filed by proponents of the ProGas proposals and proponents of extending Canadian imports under Canadian export license GL-1. 9/ The staff filed testimony comparing the economic costs and benefits of several Canadian import proposals to the prebuilding proposal, and PIT filed rebuttal testimony.

A hearing was conducted on the shipper tracking issues and separate initial and reply briefs were submitted by Northern Natural, Panhandle, United and ANB jointly, and the staff. In addition, the South Dakota Public Utilities Commission (South Dakota) submitted a reply brief on these issues.

On January 11, 1980 the Commission determined that the applications relating to the Western Leg prebuild facilities should be decided separately from those relating to the Eastern Leg. In its order severing the Eastern and Western Leg applications for decision, 10/ the Commission noted that the NEB granted separate export authorizations for specific amounts of gas to be exported through the respective prebuild facilities of the Western and Eastern Legs. 11/ That, plus the fact that the Western Leg record was concluded prior to the completion of the record on the Eastern Leg, prompted the Commission, in the interest of expedition as mandated by the Alaskan Natural Gas Transportation Act (ANGTA), to proceed with a separate decision on the Western Leg applications.

9/ The decision of the Canadian National Energy Board, (NEB) "Reasons for Decision in the Matter of Applications Under Part VI of the National Energy Board Act," Cat. No. NE22-1 1979-8 issued December 6, 1979, granted export licenses on similar terms for all competing applications. (This report is referred to hereinafter as "the NEB export decision.") In light of this, no further discussion of the Phase III issues is necessary.

10/ Western Leg Order, *supra*.

11/ Under the NEB decision, exports of gas to Pan-Alberta were expressly linked to the prebuild project. The NEB authorized 240,000 Mcf of gas per day for four years commencing November 1980, for export through the Western Leg of the prebuild project, and 800,000 Mcf per day for three years commencing November 1981, through the Eastern Leg. Gas volumes for export through each leg will decline 25 percent per year over the succeeding three years.

The Western Leg order approved the importation of 240,000 Mcf per day of natural gas from Canada and the related sale of this gas by Northwest Alaskan to PIT, and by PIT to Southern California Gas Company. That order also authorized the prebuilding by PGT of 160.5 miles of the Western Leg of the ANGTS from the point of importation near Kingsgate, British Columbia to Stanfield, Oregon, and the transportation of the import volumes through the existing facilities of Northwest Pipeline and El Paso through June 1981. Applications for rehearing of the Western Leg order have been filed 12/ and the Commission has noticed its intent to consider all such applications simultaneously when the rehearing period has elapsed. 13/

In view of our prior action regarding the Western Leg applications, the decision here will be limited to consideration of those applications related to the Eastern Leg prebuild project. 14/

12/ Rehearing has been requested by intervenors Cascade Natural Gas Corporation, Intermountain Gas Company, Washington Natural Gas Company and Northwest Natural Gas Company, jointly; California Gas Producers Association; The California Public Utilities Commission and our own Commission's trial staff, jointly; the Colorado Interstate Gas Company; and Northwest Pipeline Corporation and Pacific Interstate Transmission Company, jointly.

13/ Notices issued March 7, 1980 and April 11, 1980.

14/ Northern Border Pipeline Company (Northern Border) filed an application to prebuild 809 miles of 42-inch pipeline of the ANGTS from a point near Monchy to an interconnection with the transmission system of Northern Natural at Ventura, Iowa, and to transport and deliver approximately 800,000 Mcf per day of gas purchased by Northern Natural, United and Panhandle from Northwest Alaskan.

Northern Natural is requesting approval of its purchase of 200,000 Mcf of gas per day (commencing in the third contract year Northern Natural can increase this amount to 250,000 Mcf per day with an equivalent reduction in amounts of gas sold to United), and of its transportation/displacement and exchange agreements with Panhandle and United. It is also seeking approval of its tariff tracking proposals.

Panhandle is seeking approval of its purchase of 150,000 Mcf of gas per day and of an amendment to its FERC Gas Tariff to provide for the current full recovery of all gas purchase and delivery costs incurred in obtaining the Alberta gas.

(footnote continued on next page)

Initial and reply briefs addressing all Eastern Leg issues except shipper tracking were submitted by Northern Natural, TransCanada Pipelines Limited (TCPL), ANB and United jointly, Panhandle, Northern Border, Foothills Pipe Lines (Yukon) Ltd. (Foothills) and Pan-Alberta jointly, and the staff. Northwest Alaskan filed an initial brief on these issues and New York filed a reply brief.

II. PHASE I ISSUES

A. Relationship to the ANGTS

The sponsors noted in their Phase I briefs that the concept of importing Canadian gas through the ANGTS facilities was recognized by Canada's NEB and by the President's <u>Decision</u>. The facilities proposed to be constructed by Northern Border are the same as those selected by the President and approved by the Congress for the ANGTS, and no party in this Eastern Leg proceeding questions the interrelationship between the proposed Northern Border facilities and the ANGTS.

Upon review of the record herein we believe that the entire Eastern Leg prebuild project, including the proposed prebuild facilities from the U.S./ Canadian border to Ventura, Iowa, and the importation of Canadian gas through those facilities for re-sale under the conditions herein approved, are related to the construction and operation of the ANGTS within the meaning of Section 9 of the Alaskan Natural Gas Transportation Act.

II.B. Benefits of Prebuilding

According to the sponsors, prebuilding a portion of the ANGTS would reduce its total cost because early construction

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__/ (footnote continued from previous page)

United is requesting approval of its purchase of 450,000 Mcf of gas per day and for resale of this gas to its jurisdictional customers as well as approval of tariff tracking mechanisms for flowing through the costs associated with the acquisition and transportation of Alberta volumes.

ANB is seeking a certificate to transport 450,000 Mcf of gas per day for United through Northern Border's facilities, and for approval of tariff mechanisms to flow through the costs associated with acquisition and transportation of the Alberta gas.

of the prebuild portion would avoid cost increases caused by inflation. Also, it would spread the demand for labor and materials needed to construct the whole system over a longer period of time, thus lessening demand, which would otherwise tend to increase the cost of these items. 15/ The sponsors also contend that the added volumes of Alberta gas which prebuilding will provide will reduce the unit transportation cost of Alaskan gas.

The sponsors have alleged throughout this proceeding that prebuilding will assist in financing the ANGTS. They contend that earnings from the operation of the prebuild facilities will help the sponsors support financing of the entire project. Additionally, they argue that prebuilding will increase investor confidence in the project.

The staff concedes that prebuilding will assist financing of the ANGTS, but they point out that it will not assure financing. According to the staff, financing for the entire ANGTS cannot be assured until sufficient credit support for the debt during the construction period is arranged.

In addressing this issue in the Western Leg order, we concluded that the addition of Alberta gas into the system will reduce the unit cost of service for the Alaskan gas. We also recognized in that proceeding that prebuilding will get the ANGTS project started sooner, and that it will spread the demand for labor and capital over a longer period of time, thus lessening the likelihood of increased labor and material costs and construction delay costs due to increased demand. We also found therein that prebuilding will facilitate, though not assure, financing of the remainder of the project.

We believe that the aforementioned benefits will be even greater with respect to prebuilding a portion of the Eastern Leg, since more of the Eastern Leg of the ANGTS is to be prebuilt to carry Alberta gas. Accordingly, we conclude that prebuilding a portion of the Eastern Leg will benefit the remainder of the ANGTS.

15/ In Phase I the sponsors contended that prebuilding would reduce the delivered cost of Alaskan gas by $3.8 million dollars over a 25 year period. This figure includes early depreciation of the pre-built facilities over a 12-year life and does not reflect the change in depreciation proposed by the Northern Border sponsors.

II.C. Depreciation and Risk Allocation

One of the questions posed for Phase I of this proceeding was

> "...the relationship between the depreciation schedules for the facilities and the allocation of project risks of the pre-built facilities as well as the total ANGTS;..." (Hearing Order at 8)

The depreciation schedule proposed as part of the Northern Border prebuild project - and in fact made a condition precedent by both the equity sponsors and the banking consortium providing the debt component for financing this segment - is predicated upon an economic life for these facilities which is defined by the supplemental throughput agreement between TCPL and the other Northern Border partners. 16/ The trial staff asserts 17/ that Northern Border's depreciation proposal involves a different allocation of project risks than was contemplated by the Commission in its order establishing rates of return for Northern Border, 18/ and that if Northern Border's depreciation proposal is accepted, the Commission must adjust that company's rate of return.

Northern Border did not address this issue in its Eastern Leg briefs. Appropriate rates of return were given some attention in the sponsors' reply brief in Phase I. Their comments were in the context of appropriate level of rates of return in relationship to the rate of depreciation accrual, rather than to the relationship of depreciation to actual project risks.

In our view certain aspects of the depreciation proposals presented by the Northern Border partners do involve an allocation of project risks different from that contemplated by the Commission in Orders No. 31 and 31-B. Although we would disagree with TCPL's assertion that

> [u]nder this backstop obligation, TCPL assumes the risk of whether Alaskan gas will be available for shipment through the NB project... (TCPL Reply Brief at 22.)

16/ Exhibit NB23-A at page 4.

17/ California made essentially the same argument in its Phase I initial brief.

18/ Order No. 31, *supra*.

it is clear that, with the depreciation method proposed by the sponsors, the Northern Border partners would not be exposed to any of the risks associated with the Alaska segment. 19/

In reviewing the rationale provided in Orders No. 31 and 31-B for the approved rates of return and the context in which those orders were prepared and issued, 20/ the Commission observes that the rates of return for Northern Border contemplated some degree of exposure to the risks of completion of the Alaska segment. 21/ The Commission believes that an appropriate balance between exposure and return will be achieved by conditioning Northern Border's certificate, as we did for PGT's in our Western Leg order 22/, to require Northern Border to revise its depreciation schedule to reflect the Alaska volumes once construction of the Alaskan segment of the ANGTS has commenced. As in the case of the Western Leg, this provision will assure consideration of the Alaskan volumes for depreciation purposes at the earliest reasonable time.

19/ The risk to which we see TCPL exposed under these arrangements is that either the U.S. or Canadian Government or both would not allow it to move gas to eastern Canadian markets by way of Northern Border in the event that the Alaska volumes do not flow, and that, consequently, TCPL would have to pay for Northern Border without being able to use it. Staff observes that TCPL entered into this agreement without reservation with regard to regulatory approvals for import and re-export of these volumes (staff initial brief at 19), but the Commission observes that such approvals are routinely granted by both Governments for shipment of gas to eastern Canada by way of the Great Lakes system.

20/ When those orders were issued, the Commission contemplated attaching specific terms and conditions to any certificates for the prebuild projects which would define the relationship between them and the ANGTS as a whole. As discussed more completely *infra*., the Commission believes that extensive conditions are unnecessary in the current circumstances.

21/ See the discussion of the Project Risk Premiums for Northern Border and the Alaska segments in Order No. 31 at pages 72-80.

22/ Western Leg order at 41.

II.D. Conditions

The issue of what conditions should be attached to any certificates ultimately issued in this consolidated proceeding was first addressed by the parties in Phase I.

The project sponsors agreed therein that no conditions, other than requiring import authorization from Canada, should be attached to the prebuild certificates while the staff, joined by Michigan and California, urged the Commission to adopt an "Alaska condition" which would require that satisfactory commitments for debt and equity financing for the entire ANGTS be in place prior to the commencement of prebuild construction. In our Western Leg order we rejected the need for an "Alaska condition" on the grounds that "it would delay the flow of Canadian gas from Alberta for one to two years, and could also eliminate or reduce the benefits associated with prebuilding." None of the parties addressed the issue of the need for an "Alaska condition" in their Eastern Leg briefs, and we see no reason to modify our Western Leg findings with respect to any certificates issued to construct Eastern Leg facilities.

In its initial brief (Eastern Leg issues) Northern Border requests that any certificates issued be conditioned upon the issuance of "satisfactory" Canadian export authorizations granting additional volumes for the Pan-Alberta shippers and amending the export licenses of Consolidated Natural Gas Ltd. (Consolidated) and ProGas Ltd. (ProGas) to permit them to export through the Northern Border facilities. 24/ Other conditions proposed by Northern Border would require ProGas and Consolidated to file appropriate applications to transport their gas through Northern Border, and that the Commission find these applications required by the public convenience and necessity.

24/ ProGas and Consolidated filed applications with the NEB, ERA and the FERC, for the importation of Alberta gas at Emerson, Manitoba, for transportation through the Great Lakes pipeline system. The NEB granted export approval; the applications before ERA and the FERC are still pending. Consolidated has also filed an application with the NEB to change the point of importation from Emerson to Monchy, Saskatchewan, which application is still pending.

Only the Staff commented on Northern Border's proposed conditions. The staff supports conditioning any certificate issued herein on additional export authorization by Canada but opposes imposition of the proposed condition requiring amendments to the ProGas and Consolidated export licenses on the grounds that such amendments are not necessary to make the Northern Border prebuild project financeable.

The sponsors' request for additional export volumes and the effect of the possible shift of certain ProGas and Consolidated authorized export volumes to Northern Border is discussed in III. Phase II Issues, infra. For the reasons discussed therein we will not condition any certificates issued herein as requested by Northern Border.

III. PHASE II ISSUES

A. Financing

1. Description of Agreements and Financing Plan

a. Original partnership agreement

Northern Border was authorized by the President's Decision to construct, own and operate the United States Eastern Leg of the ANGTS. Northern Border was identified in the Decision as

> "... a partnership consisting of subsidiaries or affiliates of Columbia Gas Transmission Corporation, Michigan-Wisconsin Pipeline America, Natural Gas Pipeline Company of America, Northern Natural Gas Company, Panhandle Eastern Pipe Line Company, and Texas Eastern Transmission Corporation, or its successor,..." (Decision at 4)

As mandated in Section 5(a)(2) of ANGTA, the Commission issued a conditional certificate of public convenience and necessity to Northern Border on December 16, 1977. 25/

25/ "Order Vacating Prior Proceedings and Issuing Conditional Certificates of Public Convenience and Necessity," issued in this docket on December 16, 1977.

The possibility of constructing certain segments of the ANGTS in advance of when they would be required for Alaska gas service led to a re-structuring of the Northern Border partnership. In approving the ANGTS, the President had stated in the Decision that one of the major benefits of the designated system was that it would

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

Since certain of the original Northern Border partners had no desire to participate in the early construction of a portion of Northern Border, a new partnership agreement was negotiated and executed which became effective as of March 9, 1978. Under this agreement, the "post-certification Northern Border" succeeds to all right, title and interest of the "pre-certification Northern Border" in the conditional certificate issued on December 16, 1977 in Docket No. CP78-124.

The "post-certification" Northern Border partners are:

Partner Company	Parent
Northern Plains Natural Gas Company	Northern Natural Gas Company
Northwest Border Pipeline Company	Northwest Energy Corporation
Pan Border Gas Company	Panhandle Eastern Pipe Line Company
United Mid-Continent Pipeline Company	United Gas Pipe Line Company

Northern Border filed an application on January 26, 1979 for transfer of interest in the conditional certificate to the new partnership, and for a supplemental certificate of public convenience and necessity authorizing partial construction of the Northern Border system.

b. Entry of TCBPL into the Partnership

In late 1979, the Northern Border partnership was expanded by the entry of TransCanada Border Pipeline, Ltd. (TCBPL), a subsidiary of TransCanada Pipelines Ltd. (TCPL), the largest interprovincial natural gas transmission company in Canada. Under the provisions of the First Supplement of the Northern Border Partnership Agreement, effective October 25, 1979, TCBPL acquired a 30 percent equity interest in the Partnership, and TCPL, its parent, became obligated to purchase the remainder of the equity in the partnership under certain conditions. This purchase obligation is triggered if Northern Border's Management Committee does not determine, by the last day of the tenth year after the Billing Commencement Date (as defined in the Agreement), that the additional facilities on the Northern Border system that will be required for transportation of the Prudhoe Bay gas are to be constructed.

In return for its equity participation, TCPL agreed to execute a 15-year service agreement in which it agrees to pay the partnership minimum monthly fixed charges for transportation of certain gas volumes (that increase from year to year) whether or not these volumes are actually shipped through Northern Border. The effect of this agreement is to "backstop" the financing of Northern Border against the possibility that Canadian gas exports through Northern Border would terminate prior to the commencement of Alaskan gas deliveries through Northern Border.

Also, according to the terms of the First Supplement to the partnership agreement, TCPL agreed to try to arrange debt financing for the project. In fulfillment of that obligation, TCPL arranged for provision of the debt component of the the total capital by a banking syndicate led by the Canadian Imperial Bank of Commerce. A Summary of Terms for that loan agreement was accepted by the Northern Border partners on February 28, 1980, and filed as Exhibit NB-23A in this proceeding.

c. Conditions on the Various Agreements - TCPL's Service Agreement

Northern Border's prebuild facilities are to be financed on a project basis. Under the terms of the Financial Plan, repayment of the loan is to be paid out of the partnership's anticipated revenue stream under its tariff.

TCPL's obligations under the First Supplement and its obligation to enter into the Service Agreement are expressly conditioned on the Commission's approval of three provisions of Northern Border's tariff:

(1) Unit-of-Throughput Method of Depreciation. Northern Border proposes use of the unit-of-throughput method of depreciation predicated on a total throughput of 4.164 Tcf, which may be achieved by shipments through Northern Border of 800 MMcfd for a period of 15 years at a 95% load factor. TCPL considers the use of this method essential because it matches the depreciation charged with the actual volumes shipped each year. Thus, this method has the advantage of smoothing out the cost-of-service fluctuations due to variations in contracted throughput.

(2) Abatement of Depreciation. The First Supplement of the Northern Border Partnership agreement provides for the abatement of depreciation in any contract year, up to a maximum of four years, during which exports licensed to the Pan-Alberta shippers (Northern, Panhandle and United) for transportation through Northern Border total less than 100 Bcf on an annual basis, and annual exports of all shippers for transportation through Northern Border total less than 250 Bcf. TCPL considers this necessary to avert the imposition of excessive unit charges during periods of low throughput when TCPL's backstop obligation would take effect if the Alaskan deliveries are substantially delayed.

(3) Additional Export Volumes. The total 4.164 Tcf throughput represents the estimated useful life of the Northern Border prebuild facilities. Of this total, 1.314 Tcf has already been authorized by the NEB for export to the Pan-Alberta shippers. The remainder represents the amount of TCPL's backstop obligation. However, TCPL alleges that additional volumes must be put through Northern Border in order for it to finalize its service agreement with Northern Border. Specifically, TCPL wants the NEB to authorize an additional 279 Bcf for the Pan-Alberta shippers, and supports the shifting of 450 Bcf of authorized export volumes for ProGas and Consolidated to Northern Border, increasing the authorized throughput for these facilities to approximately 2.04 Tcf. TCPL considers 2.04 Tcf of gas as the minimum amount necessary during the first six tariff years, to support its backstop of the Northern Border project with the proposed four year abatement of depreciation charges, and to meet the lenders' requirement that

the unpaid balance of the loan at maturity (approximately 10 years after the Billing Commencement Date) be no more than 40 percent of the original amount of the loan.

Lenders' Financial Plan

Pursuant to Article X of the First Supplement, TCBPL is obligated to arrange for debt financing for the Northern Border project. The Financial Plan for the debt financing, as negotiated by TCBPL, contains the following requirements:

(1) Approval of Tariff. The lenders require a Commission order in final and unappealable form approving the Northern Border tariff. Approval of the tariff is paramount because the lenders will rely on revenues generated by the tariff for repayment of the Northern Border debt.

(2) Effectiveness of TCPL's Service Agreement. The financing of the Northern Border project is predicated on TCPL's execution of an acceptable Service Agreement and the Commission's approval of that Agreement. All Northern Border shippers are obligated to pay a share of the project's cost of service under some form of ship or pay agreement. For all partners except TCPL, the cost-ofservice obligation for each shipper is based on the amount of gas that company has contracted to ship through Northern Border each year, rather than actual throughput volumes. TCPL, on the other hand, would be obligated to ship or pay for certain minimum volumes, specified in advance in the TCPL Service Agreement. If there are no Pan-Alberta exports authorized for shipment through Northern Border and Alaskan gas is not flowing, TCPL is obligated to pay Northern Border's full cost of service. TCPL's obligations are to pay charges attributable to the greater of:

(a) the largest volume of gas transported for TCPL's account during any preceeding tariff year; or

(b) the lesser of:

(i) 50 Bcf of gas starting with the fifth year and increasing by 25 Bcf for each succeeding year through the fourteenth year; or

(ii) the volume of gas necessary to ensure that 292 Bcf of gas is transported through NB each year.

TCPL's obligation is subject to deferral of depreciation charges under certain conditions. (See the discussion of the abatement provision, infra.)

(3) TCPL Contingent Obligation to Purchase the Northern Border System. According to Article IX of the First Supplement to the Northern Border partnership agreement and the Financial Plan, TCPL will have the obligation to purchase the Northern Border system under certain conditions. If on the final day of the tenth year after the Billing Commencement Date, the Northern Border Management Committee has not determined that the incremental facilities are to be constructed to transport the Prudhoe Bay gas, TCPL will acquire full control of the pipeline by exercising one of its options to purchase (i) all of the interests in the partnership, or (ii) the partnership assets, or (iii) all of the partners' stock.

(4) Unit-of-Throughput Depreciation Method. The Financial Plan also contains conditions precedent requiring Commission approval of the cost-of-service arrangements including depreciation based on the unit-of-throughput method with a total throughput of 4.164 Tcf over the life of the project. This entails depreciation abatement, up to a maximum for four years, should licensed Pan-Alberta exports for transportation through Northern Border total less than 100 Bcf and exports of all shippers for transportation through Northern Border total less than 250 Bcf. The depreciation issues are discussed more fully below.

III.A.2. Depreciation Issues

a. Depreciation Methodology

The project sponsors and their bankers, for all of the reasons discussed above, state that they require use of the unit-of-throughput method of depreciation. The unit-of-throughput method is the same as the unit-of-production method which has been employed by the Commission to determine depreciation rates for gathering facilities and certain transmission facilities. Utilizing this method, the economic life of a facility is determined by calculating the total units (i.e., volumes of gas) that are expected to flow through the facility. Under this method, the depreciation expense for any year is based upon the degree of utilization of the facility relative to the total expected throughput.

The staff, on the other hand, supports use of a "straight-line" depreciation methodology, i.e., a methodology which yields constant depreciation charges for each year of the project's economic life, irrespective of variations in contracted throughput volume.

The project sponsors and the staff both refer to the standards for deciding depreciation issues set forth in Memphis Light, Gas and Water Division v. Federal Power Commission, 504 F.2d 225 (D.C. Cir. 1974). The project sponsors cite a number of instances wherein the Commission has approved unit of throughput depreciation methodology under the Memphis standard, and note that the Commission endorsed PGT'S use of this methodology in the Western Leg order.

The Commission believes that the unit-of-throughput methodology is appropriate for the Northern Border prebuild. The throughput on which the prebuilding of Northern Border is based, the Pan-Alberta exports and the TCPL backstop commitment, will vary significantly from year to year. Use of straight-line depreciation could provide pipeline operators an incentive to take necessary actions - either contracting for additional gas supplies or seeking additional gas customers - in an effort to stabilize system throughput. However, past experience has shown such actions have had little effect on the time profile of availability of imported gas supplies. In the case of PGT, for example, export licenses were granted to its suppliers in 1960, 1966, and 1970, on each of which occasions new facilities were added and the total committed throughput volume was revised. After those three occasions, PGT's supplier received no new export authorizations until the recent NEB order. 26/ Accordingly, the Commission approves the unit-of-throughput depreciation method for the prebuild segment of Northern Border.

26/ This history is discussed in the NEB's December 6 order, supra. In that order, certain of the existing export licenses for PGT's supplier were extended, and a new supplier was added for the prebuild project. Both of these commitments of additional volumes to export required revisions to the total throughput for purpose of establishing PGT's economic life.

b. Economic Life of the Facilities

Staff argues that the criteria for establishing the economic life of these facilities, as articulated by the Court of Appeals in the *Memphis* decision, *supra*, requires the inclusion in that computation of the Alaska gas volumes that are expected to flow through these facilities. Staff goes on to argue that the Commission erred in taking financial considerations into account in deciding not to include Alaskan volumes in its determination of the economic life of the facilities authorized for the Western Leg of the ANGTS.

The project sponsors allege that

> "... 4.164 Tcf throughput represents the known useful life of the NB pre-build facilities under the presently authorized Canadian export licenses and the TCPL backstop." (TCPL Initial Brief at 3)

and that that useful life defines that project's economic life for purposes of establishing the appropriate rate of depreciation under the *Memphis* standards. TCPL, in response to staff's arguments regarding the role of financing considerations in establishing depreciation rates, argues in terms of financial "limitations" imposed on both the Western Leg and Northern Border because of their relatively short "... known useful life under present conditions,..." (TCPL reply brief at 7).

The Commission believes that arguments about "limitations" imposed by financing are beside the point here. Our reading of the *Memphis* case as applied to both the Western Leg and the circumstances here is that "... the Commission is obligated to ascertain the useful life of the particular piece of depreciable property involved" (504 F.2d at 231). In *Memphis*, exhaustion of gas supply had caused the useful life of the facilities in question to be reduced to less than their physical life. In the instant case, because of the requirement for export and import authorizations, and because of the requirements on the various parties to this project to bring it to fruition within the parameters of national policies of two countries, we believe the useful life of the facilities to be constructed is defined by the various agreements among the parties who plan to use those facilities. It is a possible though not probable outcome that these facilities would only be used to transport gas under the presently authorized

Canadian exports and the TCPL backstop agreement; thus, those two uses of the facilities define their useful life until it is established that the facilities will be used for additional purposes. 27/

The relevance of financing considerations is in making the transition from expectation to commitment. As Northern Border states:

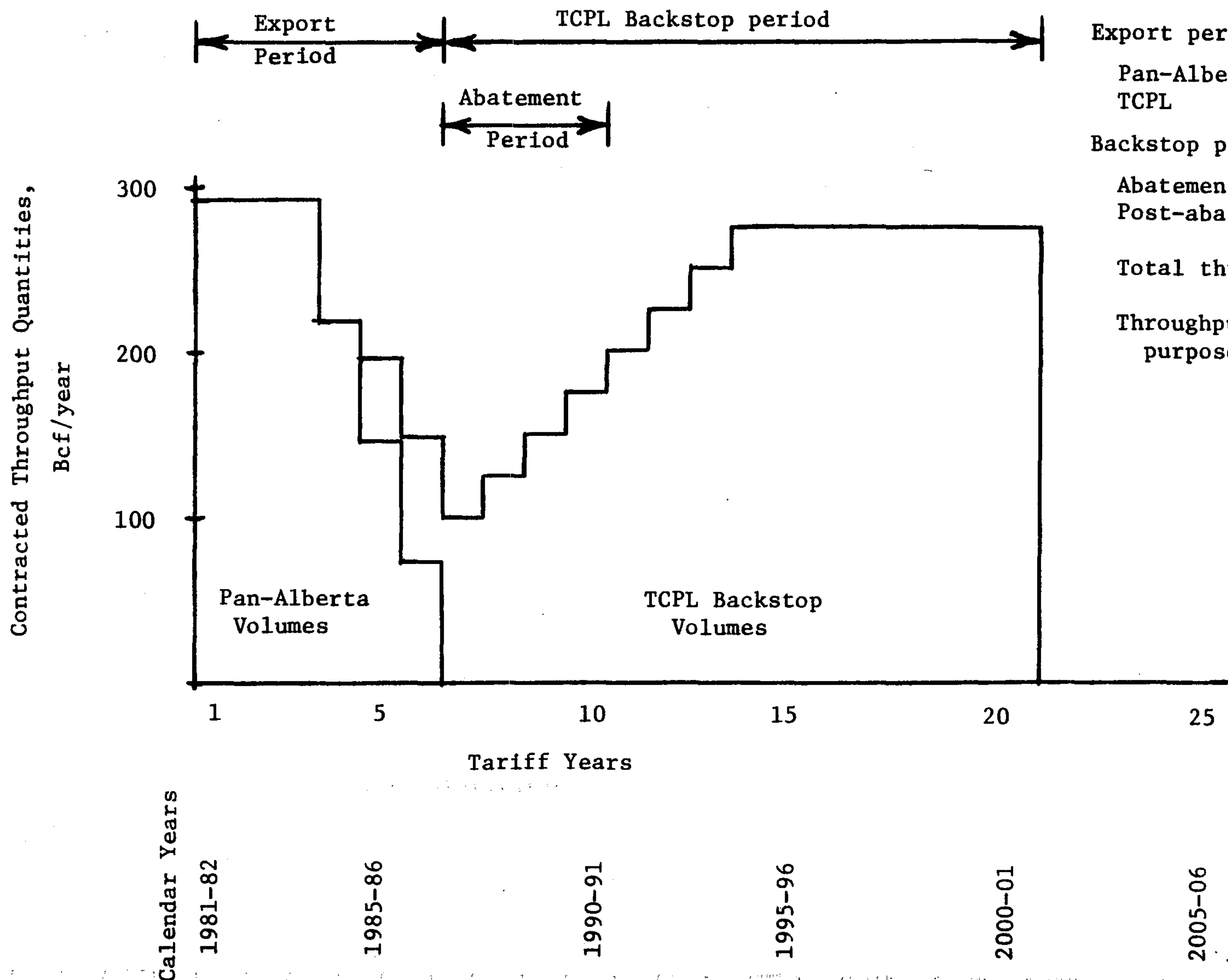
> "Economic life and financing are inextricably intertwined, because investors insist on assurance of recovery of investment, and to achieve this the investment must be amortized, and the facilities thereby depreciated, over what investors perceive to be their economic life.... Initial investors are unwilling to commit funds for a new project based on any speculation of added economic life beyond the limits of the economic life which is committed on the project at the time of initial financing. After construction of the project, if the speculative increments of economic life are in fact realized, both the period of investment recovery and depreciation rates may be modified to reflect what then has become a longer assured economic life." (Northern Border Reply Brief at 30-31) (Emphasis added)

For these reasons, the Commission determines that the economic or useful life of the Northern Border prebuild facilities is defined by the presently authorized Canadian export licenses associated with those facilities and the TCPL backstop obligation. For purposes of clarity, the Commission includes on the next page a diagram depicting throughput of the committed exports and the TCPL backstop obligation as they are understood by the Commission. On that and the two succeeding pages are diagrams illustrating our understanding of the impact on the economic life of the project of the additional export volumes applied for the benefit of the Pan-Alberta shippers, Northern Natural, Panhandle and United.

27/ Staff effectively concedes this point by proposing to re-evaluate the depreciation rate after 2 years.

ECONOMIC LIFE OF THE NORTHERN BORDER PRE-BUILD FACILITIES

CASE I: Currently Authorized Export Volumes, TCPL Backstop Volumes

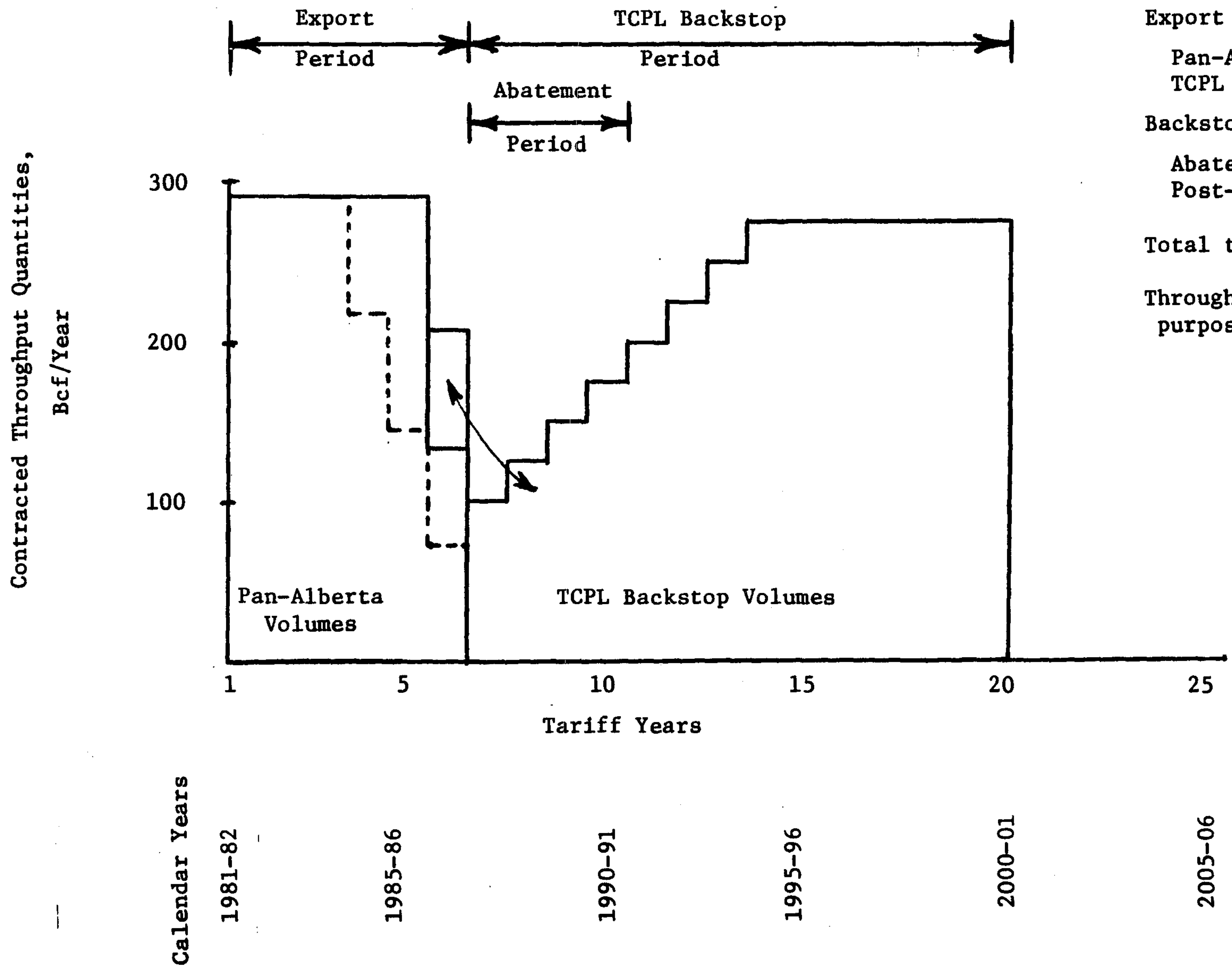


Contracted throughput, Bcf	
Export period	
Pan-Alberta shippers	1314
TCPL	125
Backstop period	
Abatement period	550
Post-abatment period	2725
Total throughput	4714
Throughput for depreciation purposes (4714-550)	4164

ECONOMIC LIFE OF THE NORTHERN BORDER PRE-BUILD FACILITIES

CASE II: Authorized plus Applied-For Export Volumes, TCPL Backstop Volumes

Fall '81 In-Service Date

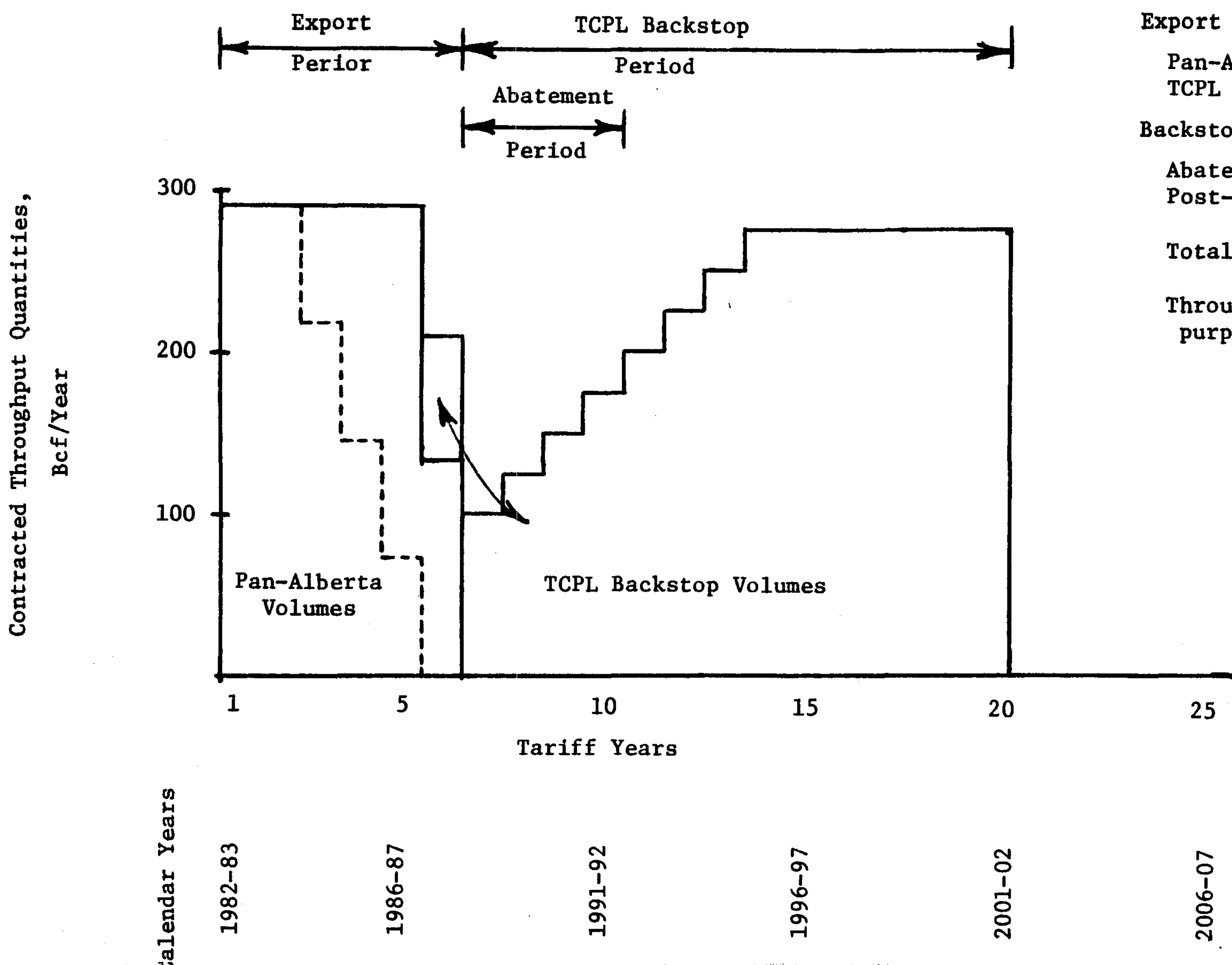


Contracted throughput, Bcf	
Export period	
Pan-Alberta shippers	1593
TCPL	75
Backstop period	
Abatement period	550
Post-abatement period	2496
Total throughput	4714
Throughput for depreciation purposes (4714-550)	4164

ECONOMIC LIFE OF THE NORTHERN BORDER PRE-BUILD FACILITIES

CASE III: Authorized plus Applied-For Export Volumes, TCPL Backstop Volumes.

Fall '82 In-Service Date



Contracted throughput, Bcf	
Export period	
Pan-Alberta shippers	1593
TCPL	75
Backstop period	
Abatement period	550
Post-abatement period	2496
Total throughput	4714
Throughput for depreciation purposes (4714-550)	4164

c. Abatement of Depreciation

As we have noted, the First Supplement of the Northern Border Partnership Agreement provides for the abatement of depreciation in any contract year, up to a maximum of four years, during which licensed exports of gas for the Pan-Alberta shippers for transportation through Northern Border total less than 100 Bcf, and exports of all shippers for transportation through Northern Border total less than 250 Bcf. 28/ The staff objects to the abatement proposal on two grounds:

1) that depreciation must accrue as a facility is used, and

2) that the abatement provison violates Section 4(b) of the Natural Gas Act because its allows shippers during the abatement period to have an undue preference over shippers (a) prior to the abatement period and (b) after the abatement period, and also because it maintains an unreasonable difference in rates and charges between U.S. prebuild shippers, TransCanada, and U.S. Alaskan gas shippers.

TCPL provides the response for the project sponsors, arguing that

> "...the depreciation abatement provison of the NB Tariff is necessary to prevent the imposition of onerous unit charges during the periods of low throughput on the NB system." (TransCanada reply brief at 9)

1. The Policy Considerations

As the Commission understands it, the effect of the abatement provision is to defer, in certain circumstances, depreciation charges from a period of low throughput to a period of higher throughput. The fact that the depreciation charges are simply deferred may be best appreciated by considering specific examples. The Commission observes that the limited

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28/ Included in the 250 Bcf total is gas that TCPL would export and then re-import for distribution in eastern Canada.

circumstances in which the abatement provisions are utilized are: 1) if Alaska gas is delayed, or 2) if Alaska gas never flows at all. The Commission has developed two throughput scenarios which it believes encompass these possible situations. Diagrams describing these two scenarios are presented on the next few pages, and the scenarios and their anticipated effects are discussed herein.

The first scenario is for the case of no Alaska gas at all. It calls for 5 1/2 years of contracted throughput from the Pan-Alberta shippers that will result if their request for additional export volumes, currently pending before the Canadian National Energy Board, is granted. In addition to the Pan-Alberta volumes, only the maximum TCPL ship-or-pay throughput volumes as specified in Article VIII of the First Supplement to the Northern Border Partnership Agreement and in the Trans-Canada Service Agreement, are contracted for shipment.

There are two charts illustrating each scenario: one depicting actual contracted throughput and the other depicting throughput for depreciation purposes giving effect to the abatement provision. For the first scenario, the depreciation charges to TCPL are deferred from the abatement period (tariff years 7-10) to the extension period that is provided by the throughput agreement in the event of exercise of the abatement provision. 29/

The other scenario is for the case of a delay in the commencement of Alaskan deliveries. It illustrates our understanding of what would happen in the event that the abatement provision was triggered, but that the Alaskan volumes commenced flowing at the end of the abatement period. In this case, TCPL's depreciation charges would be deferred from the abatement period to the sixth through the ninth years of Alaskan gas deliveries. Because of the provision in the First Supplement and in the Service Agreement requiring TCPL to continue to ship through the remainder of the effective period of those agreements the largest volumes it had shipped in any prior tariff year, 30/ TCPL in this scenario

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29/ The extension period is provided by Article VIII(2) of the First Supplement, found on pages 10 and 10A.

30/ TCPL's continuing obligation to ship is limited by available capacity on the Northern Border system. See Article VIII(3) of the First Supplement at page 11.

retains responsibility for more depreciation throughput units than it abated: 700 Bcf versus 550 Bcf in the case presented. 31/

The Commission is sympathetic to TCPL's problem of high unit charges during periods of low throughput; indeed, the Commission's reason for providing for an interim rate during the first year of operation for both Northern Border and the Alaska segment was to avoid precisely this problem. 32/ The abatement proposal 33/ appears to us to be an alternate method

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31/ This effect is reduced for shorter delays, but TCPL never retains responsibility for less throughput units than it abated.

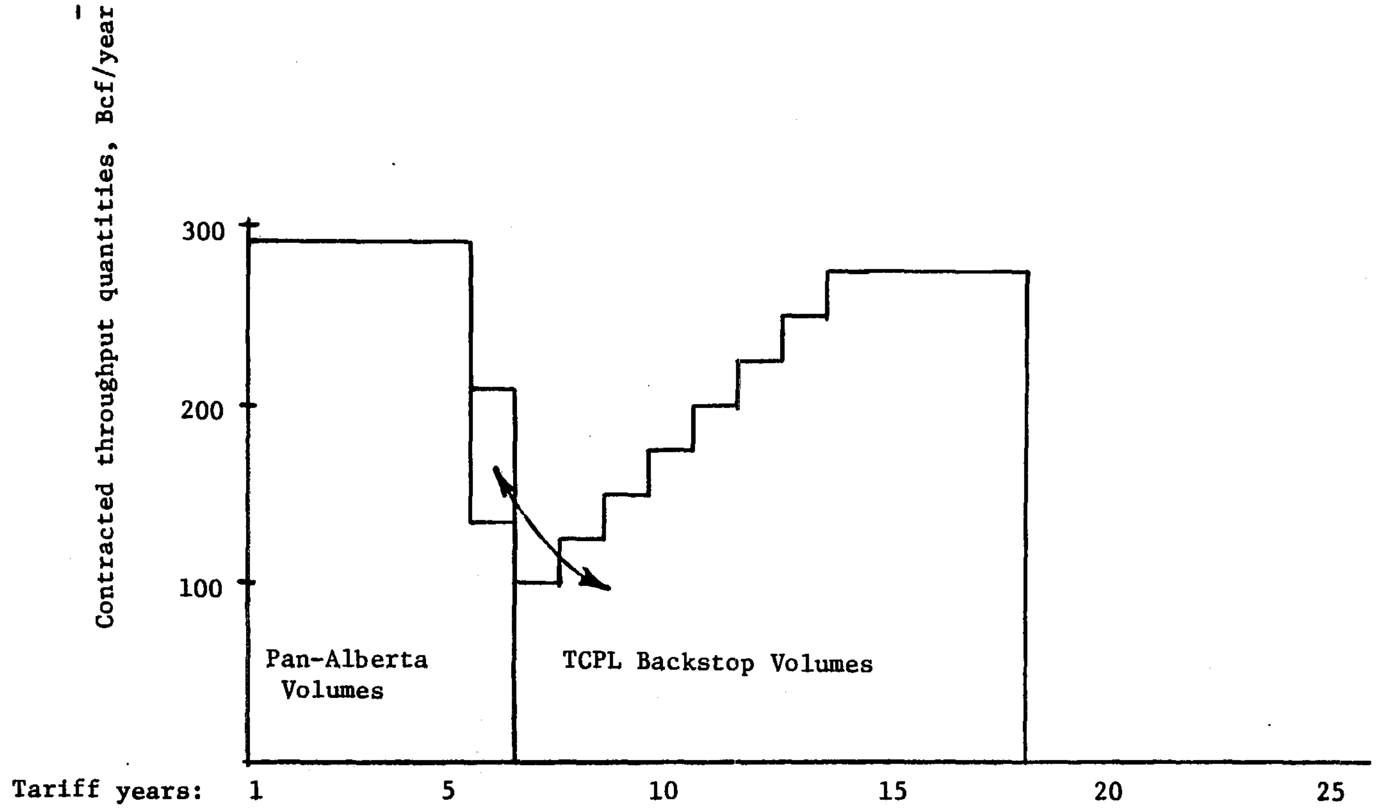
The Commission is of course aware that TCPL would be paying depreciation charges during the period when Alaskan gas is flowing which would be considerably less than the unit depreciation charges which they were allowed to abate. This difference arises because the total number of depreciation throughput units which defines the economic life of the prebuilt facilities will be increased in consideration of those Alaskan volumes, and thus the undepreciated portion of the cost of those facilities will be spread over a much larger number of units of throughput. TCPL will, however, be paying unit depreciation charges during the period when Alaskan gas is flowing which are the same as those paid by all other shippers during that period.

32/ See the discussion of the requirement for an interim rate at pages 164-173 of Order No. 31, supra.

33/ The words "abatement of depreciation" are somewhat inaccurate as a description of the effect of the contractual provision. The word "abatement" connotes a reduction or decrease, whereas the effect of this provision is more in the nature of a deferral. A tax abatement, for example, is a diminution or decrease in the amount of tax imposed upon a person. Black's Law Dictionary (4th ed. 1968); Rogers v. Gookin, 85 N.E. 405 (Mass). An abatement of a debt is a reduction in the debt made by the creditor for the prompt payment of the debt by the debtor. Black's Law Dictionary, supra. However, we will continue in this order to use the term "abatement provision" to avoid confusion, as all the documents in the record use the term.

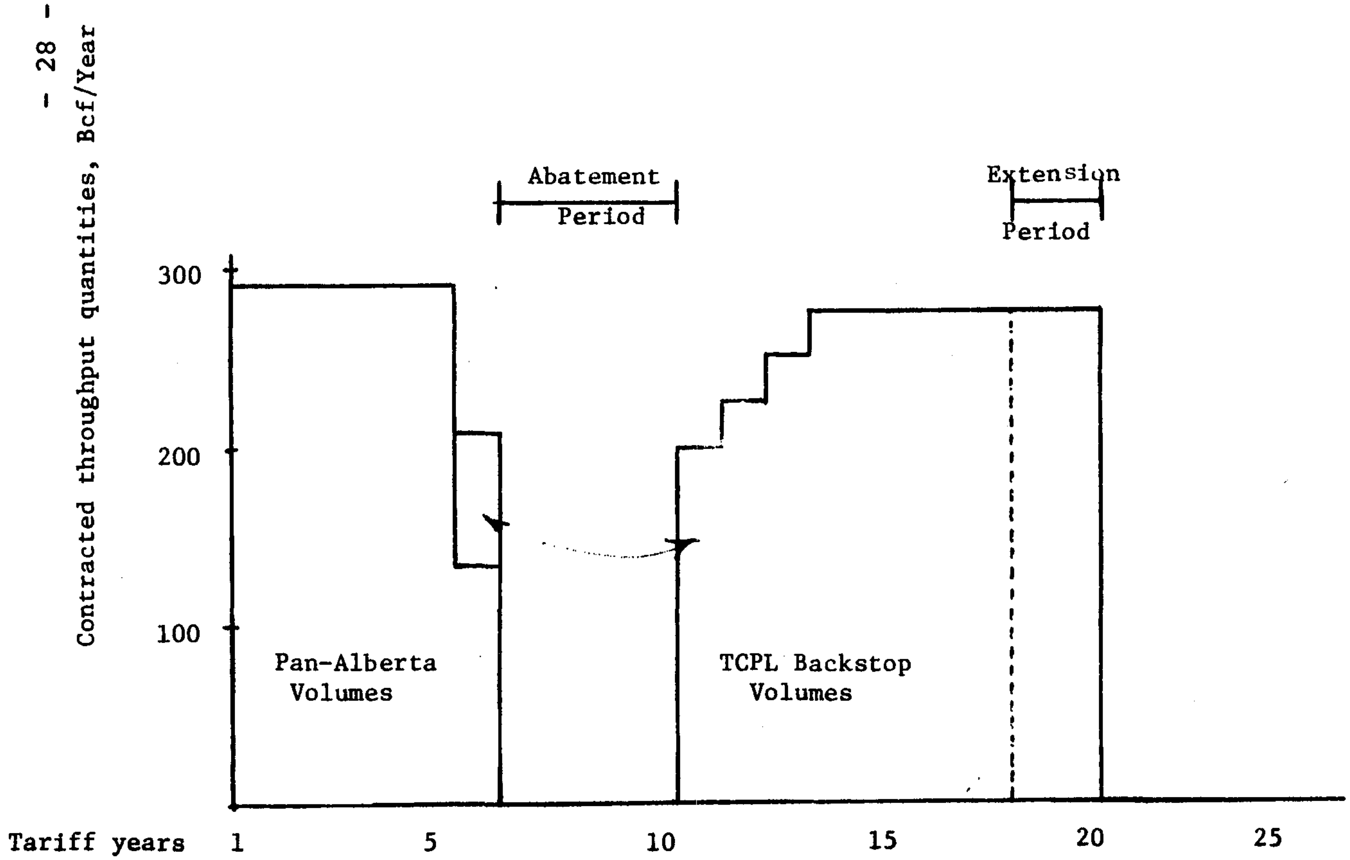
Scenario I: No Alaska gas

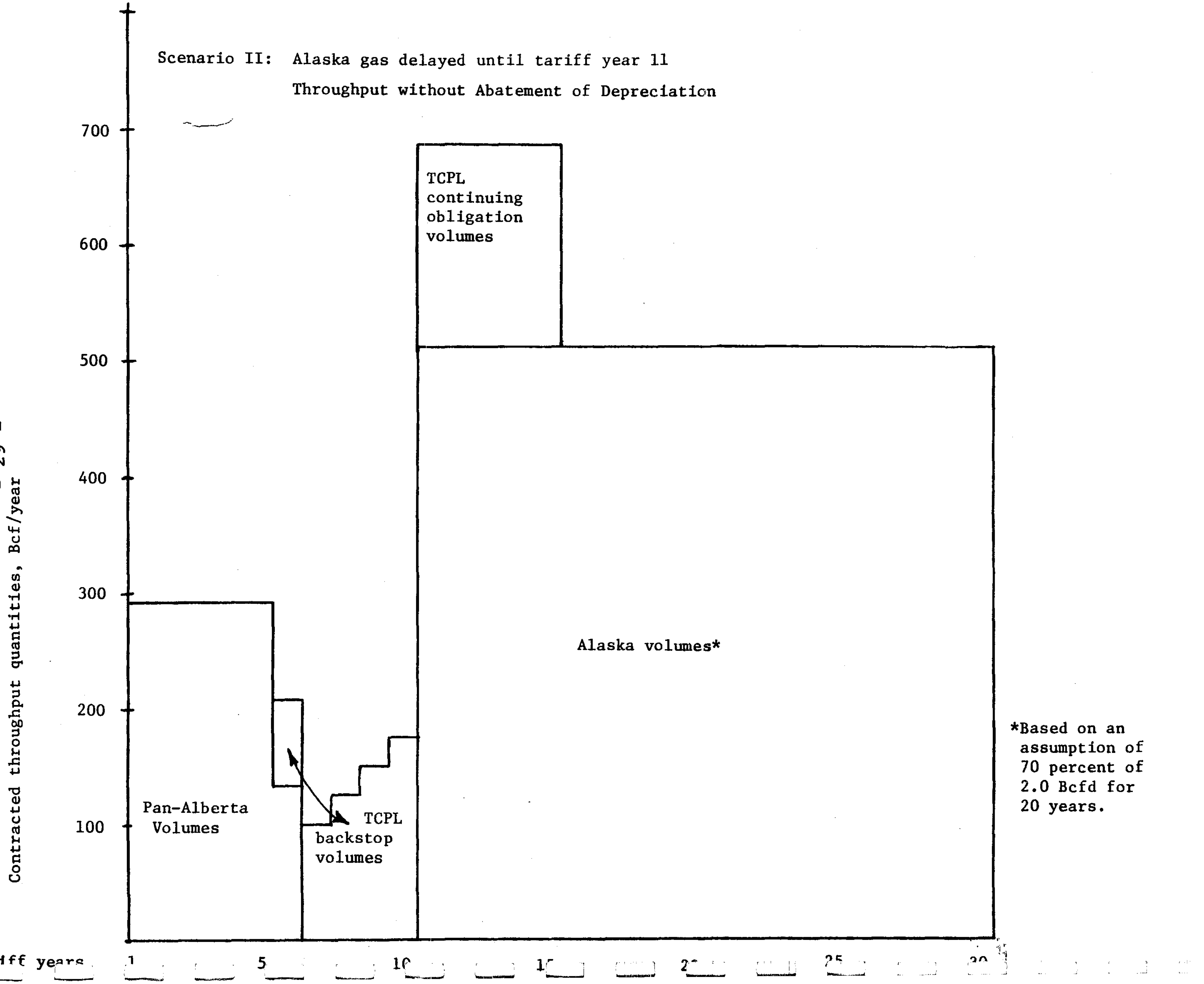
Throughput without Abatement of Depreciation



Scenario I: No Alaska gas

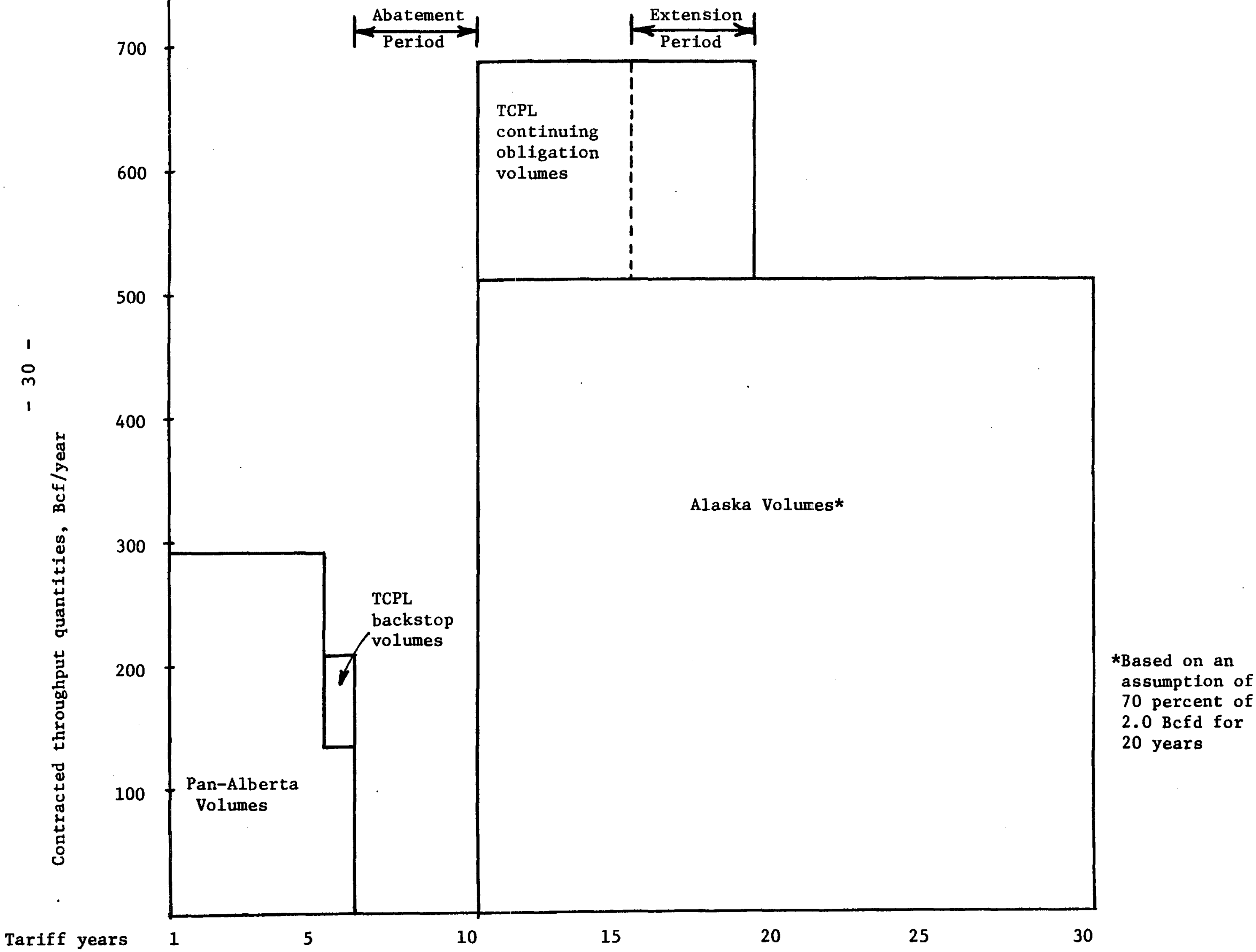
Throughput for Depreciation Purposes Giving Effect to Abatement Provision




Scenario II: Alaska gas delayed until tariff year 11
Throughput without Abatement of Depreciation
Contracted throughput quantities, Bcf/year
700
600
500
400
300
200
100
TCPL continuing obligation volumes
Alaska volumes*
Pan-Alberta Volumes
TCPL backstop volumes
*Based on an assumption of 70 percent of 2.0 Bcfd for 20 years.
Tariff years
1
5

Scenario II: Alaska gas delayed until tariff year 11

Throughput for Depreciation Purposes giving Effect to Abatement Provision



of achieving the result that the Commission was seeking with its provision for an interim rate.

There probably are other methodologies by which unit charges could be reduced during a period of reduced throughput. 34/ We observe that all of the alternatives would undoubtedly entail additional financing charges of some type, and, absent a showing of a materal difference in additional financing charges among the alternatives, we can see no compelling reason to choose one of the alternatives over another. Given that the timing of commencement of deliveries of Alaskan gas is not yet precisely fixed, and future commitments of Canadian gas to the export market are inconclusive at this time, we believe that the depreciation abatement proposal is acceptable with certain modifications as discussed below. The Commission does not agree with staff's argument that depreciation theory requires a depreciation component in all of Northern Border's charges at all times.

The inclusion of an abatement provision is a condition to TransCanada's agreement to participate in the project. The Commission has examined the provision and found that, in essence, it defers some payment of depreciation charges during a period of low volume throughput to a period of higher volume throughput. As a result, the Commission does not believe that the interests of U.S. consumers would be prejudiced, and thus finds the provision basically acceptable. However, we think the provision should be modified in several respects.

The Commission notes that the abatement provision applies to shippers using Northern Border other than TCPL. 35/ The

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34/ Some type of levelized tariff is another example.

35/ As noted above, the abatement provision is triggered when both Pan-Alberta export shipments are less than 100 Bcf/year and total shipments are less than 250 Bcf/year. The Commission views those circumstances as unlikely because the Commission expects that 1) Alaska gas will be flowing prior to the end of the export period, or 2) the Pan-Alberta export licenses will be renewed by the Canadian Government, or 3) both. However,

(footnote continued on next page)

Commission has some question regarding whether it would be equitable to abate depreciation charges for shippers other than TCPL.

The provisions of the U.S. Shippers' Service Agreement and the TransCanada Service Agreement with Northern Border are quite different. The Service Agreement between the U.S shippers and Northern Border provides that these shippers will pay a proportionate amount of the Northern Border cost of service based upon the ratio of their contracted shipments to the total of all contracted shipments through Northern Border. However, as the volume of licensed exports declines, the charges to the U.S. shippers for transportation of gas through Northern Border also decline. If licensed exports through Northern Border cease altogether, the payment obligations of U.S. shippers terminate.

Unlike the U.S. shippers, TCPL is required to make payments based on certain specified volumes regardless of whether it transports any gas through Northern Border. The effect of this provision is that TCPL is required to pay an increasing proportion of Northern Border's cost of service as Canadian exports decrease and as the payment obligations of U.S. shippers decrease. If Canadian exports terminate before Alaskan

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35/ (footnote continued from previous page)

in the unlikely event that the abatement provision is triggered, there appear to be two sets of possible circumstances wherein depreciation charges could be abated for shippers other than the Pan-Alberta shippers and TCPL such as when

1) a third party shipper agrees to discharge some part of TCPL's obligation under its Service Agreement to ship or pay for certain minimum volumes specified in Article 1(b) of that Service Agreement; and,

2) during the abatement period, a third party shipper uses the system under the provision of the U.S. Shippers' Service Agreement.

The second set of circumstances would occur at throughput levels between TCPL's ship-or-pay minimums and the 250 Bcf/year threshold for triggering the abatement provision.

gas flows, and the payment obligations of U.S. shippers cease, TCPL is obligated to pay Northern Border's full cost of service except for depreciation. This obligation continues until the Northern Border partners have recovered their investment or until Alaskan gas begins to flow through Northern Border. 36/

Because of these differences between the situation of TCPL and other shippers, particularly shippers other than the Pan-Alberta shippers, the Commission finds that it is certainly unnecessary and probably inappropriate to allow shippers other than TCPL to abate depreciation.

The Commission is also concerned about the possibility of inequities in transportation charges among users of the transportation system. In particular, the possibility exists under the proposal that depreciation charges could be abated to shippers other than the Pan-Alberta shippers or TCPL during the abatement period, but that those third-party shippers might not continue to be users of the system after the abatement period. The problem would be that such third-party shippers would seem to be paying less than their fair share.

In view of these concerns, the Commission finds that it is appropriate to allow TCPL 37/ to utilize the abatement feature only up to the throughput volumes represented by its ship-or-pay minimum obligations as specified in Article VIII(4) of the First Supplement to the Partnership Agreement, and in Article 1(b) of the TransCanada Service Agreement. For volumes shipped in excess of those minimums, but shipped under conditions which would trigger the abatement provison, the Commission believes that a different provision is in order.

36/ As discussed more fully above (see p. 17 *supra*), TCPL is obliged by Article IX of the First Supplement to the Partnership Agreement to purchase the interests of the other Northern Border partners if, by the final day of the tenth contract year, Northern Border's Management Committee has effectively conceded that Alaskan gas will not flow.

37/ The Commission will also allow TCPL to assign the abatement privilege to any shippers that it designates pursuant to Article 1(b) of the TransCanada Service Agreement to fulfill its obligations under that Service Agreement. The reasons for allowing such assignment are the same as the reasons for allowing the abatement provision in the first instance.

An alternative which appeals to the Commission is to require shippers for throughput at levels between the TCPL ship-or-pay minimums and the 250 Bcf/year threshhold at which the abatement provision is effected to pay per-unit charges developed according to the interim rate methodology approved in Order No. 31. 38/ The Commission observes that, if the design capacity throughput for establishing the interim rate is fixed at 800 MMcfd, the unit charges will be derived in the same manner as those during the export period. Such unit charges would also be similar to those in the post-abatement period which would result at the higher levels of throughput under the TCPL throughput agreement if the Alaskan volumes do not flow.

The Commission also believes that it is unnecessary to permit TCPL to abate all depreciation charges when volumes being transported through Northern Border exceed those mininum levels it is required to either ship or pay for by the Service Agreement. The problem of excessive unit costs during periods of low throughput is ameliorated as throughput volumes approach the 250 Bcf level 39/ which triggers the abatement provision. 40/

38/ See, Order No. 31 at 164-173.

39/ 250 Bcf/yr is equivalent to a year-round average of 685 MMcf/day.

40/ The following chart from staff's reply brief (at 15) illustrates this point:

TRANSCANADA PIPELINES LIMITED
ESTIMATED COST PER MCF DURING DEPRECIATION ABATEMENT
ASSUMING VARIOUS VOLUMES

	1988	1989	1990	1991
Allocated Charges ($000)	$146,391	$140,415	$135,337	$144,437
Cost per Mcf Based On:				
200 MMcf/D	$2.00	$1.92	$1.85	$1.98
300 MMcf/D	1.34	1.28	1.24	1.32
400 MMcf/D	1.00	.96	.93	.99
500 MMcf/D	.80	.77	.74	.79
600 MMcf/D	.67	.64	.62	.66

The allocated charges are from Exhibit #S-29, Ex. 46.00, line 28.

Therefore, we will only allow TCPL to abate depreciation charges for those throughput volumes which are in the same amount or less than it is required to ship or pay for by its minimum obligation; for those throughput volumes which are in excess of this level, the Commission will require TCPL and all other shippers to pay transportation charges to Northern Border which are developed in accordance with the interim rate methodology specified in Order No. 31. At throughput volumes above 250 Bcf/year, Northern Border's full cost of service will be charged to all shippers including TCPL, as provided in the First Supplement and the TransCanada Service Agreement.

2. The Legal Considerations - Rate Discrimination

We turn now to Staff's argument that the abatement proposal, if allowed to go into effect, would violate Section 4(b) of the Natural Gas Act. Section 4(b) prohibits natural gas companies from granting their customers undue preferences or maintaining unreasonable differences in rates charged different customers.

Staff argues that the abatement provision violates both aspects of Section 4(b). It allows shippers during the abatement period to have an undue preference over shippers (a) prior to the abatement period and (b) after the abatement period, and also maintains an unreasonable difference in rates and charges between the U.S. prebuild shippers, TransCanada, and U.S. Alaskan gas shippers.

The statutory bar against rate discrimination promotes twin public policies: fairness and competition. The provision in the Natural Gas Act prohibiting rate discrimination is closely modeled on the Interstate Commerce Act, 49 U.S.C.A. §10,741 (Supp. 1978). The purpose of the latter is "...to prevent favoritism by insuring equality of treatment on rates for substantially similar services..." 41/ The statutory bar also protects some consumers from being placed at a competitive

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41/ U.S. v. Chicago Heights Trucking Co., 310 U.S. 344, 351 (1940). See also Ayrshire Collieries Corp. v. U.S., 335 U.S. 573 (1949); I.C.C. v. Delaware L&W Co., 220 U.S. 235 (1911); I.C.C. v. Alabama Midland R. Co., 168 U.S. 144 (1897).

disadvantage with respect to other consumers. 42/ Where services are rendered under substantially similar conditions, the Natural Gas Act prohibits differences between shippers on the basis of their identity, 43/ or on the basis of competitive conditions which may induce a carrier to offer a reduction in rates to one shipper while denying it to another similarly situated. 44/ Mere discrimination does not render a rate illegal under Section 4(b). It is only when a preference or advantage accorded to one customer over another is undue or a difference in service or rates between them is unreasonable that Section 4(b) of the Act comes into play. Michigan Consol. Gas Co. v. F.P.C., 203 F.2d 895, 901 (3rd Cir. 1953). The determining factor is whether there are factual differences justifying different treatment of different customers. St. Michael's Utilities Comm'n v. F.P.C., 377 F.2d 912 (4th Cir. 1967). 45/ The standard set forth in St. Michael's was clarified in Public Service Co. of Indiana v. F.E.R.C., supra, where the court held that, once a party has shown a substantial disparity in rates of various customers existed, the burden of proof shifts to the company proposing the rate to justify the disparity on the basis of factual differences.

42/ St. Michaels's Utilities Commission v. F.P.C., 377 F.2d 912, 915 (4th Cir. 1967); Public Service Co. of Indiana v. F.E.R.C., 575 F.2d 204 (7th Cir. 1970). These cases construe Section 205(b) of the Federal Power Act, 16 U.S.C. §824(b), which is in substance identical to Section 4(b) of the Natural Gas Act.

43/ I.C.C. v. Baltimore and O.R. Co. 225 U.S. 326, 342 (1912).

44/ Wright v. U.S., 167 U.S. 512, 516-518 (1897).

45/ In St. Michael's, the Court stated:

> "Thus, it has been said that differences in rates are justified where they are predicated upon differences in facts - costs of service or otherwise - and where there exists a difference in rates which is attacked as illegally discriminatory, judicial inquiry devolves on the question of whether the record exhibits factual differences to justify classifications among customers and differences in rates charged them." (377 F.2d at 915).

An early decision of the Federal Power Commission construing Section 205(b) of the Federal Power Act indicated some of the factual differences which might justify differences in rates. In Otter Tail Power Company, 2 F.P.C. 134 (1940), a power company had sought to justify the different rates charged its municipal customers on the basis of their population sizes and the results of "individual negotiation and bargaining between the [company] and the municipality...involved" (2 F.P.C. at 142). The Commission had found that since there were no substantial variation in the service conditions, the characteristics of the delivery and sale, or in the costs of serving the different customers, the company had been engaging in illegal rate discrimination.

We agree with staff that the abatement provision, by relieving abatement period shippers, particularly TransCanada, of paying depreciation charges for any contract year, up to four years, during which licensed Pan-Alberta exports are less than 100 Bcf and total throughput is less than 250 Bcf, grants such shippers a preference over other shippers and establishes a disparity in rates between shippers. However, the critical point is that it is not an undue preference or an unreasonable disparity. The project sponsors have fully met their burden of showing that the factual differences between the situations of TCPL and other shippers justify this specific difference in rates. St. Michaels's Utilities Comm'n v. F.P.C., supra. The Commission's required changes for abatement period shippers other than TCPL will limit the preferential treatment to the only party for which such treatment is warranted, namely TCPL, and to the circumstances for which that treatment is warranted, namely a total throughput which is less than or equal to TCPL's ship-or-pay mininums.

We have already discussed the significant differences between the provisions of the U.S. Shippers Service Agreement and the TransCanada Service Agreement. As explained, unlike the U.S. shippers, TCPL is required, under its "backstopping" obligation, to make payments to Northern Border based on certain volumes specified in the Service Agreement regardless of whether it transports any gas through Northern Border. As the volumes of licensed exports decline, the charges to U.S. shippers for transportation of gas through the system decline; in contrast, TCPL is required to pay an increasing portion of Northern Border's cost of service.

Depreciation will be abated during a period of low throughput occurring between the reduction or cessation of Canadian export shipments and the initiation of Alaskan shipments. The effect of the provision is to reduce the extent to which unit costs will rise due to the decrease in volumes of gas being shipped through Northern Border. TCPL during this period will be paying all the components of Northern Border's cost-of-service, except depreciation.

Because of the backstop obligation, TCPL would incur a significantly higher unit cost-of-service than shippers during previous periods if the depreciation charges were not abated. TCPL introduced into evidence a table which showed the comparative unit cost-of-service for U.S. shippers and TCPL. After the hearing was closed, the sponsors revised their proposal to include an additional 279 Bcf of Pan-Alberta exports. Staff then revised the table submitted by TCPL to show the comparative unit cost-of-service based on volumes of gas which included these additional Pan-Alberta volumes. Staff presents the following table in its reply brief (at 14):

NORTHERN BORDER UNIT COST-OF-SERVICE
(cost/Mcf)

	U.S. Shippers (Ventura)	TransCanada (Ventura)
1981	128.2	
1982	122.0	
1983	111.3	
1984	98.0	
1985	91.7	
1986	88.9	116.0
1987	111.4	148.7
1988		199.7
1989		113.2
1990		98.6
1991		97.9

This table derives from Exhibit 29, which contains computer runs showing Northern Border's cost-of-service. The figures for TCPL do not include depreciation charges during the four abatement years (1988-1991). 46/ The per unit charge for depreciation is 35.1 cents per Mcf. If one adds this depreciation

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46/ These abatement years assume a fall, 1981 in-service date. Abatement may occur from tariff years seven through ten. If the in-service date changes, the abatement years will also change.

charge to the unit costs for TCPL, its unit cost-of-service is substantially higher than that of the U.S. shippers.

The figures in the above table are based upon volumes of gas which TCPL expects to transport through Northern Border, and not upon what it actually is required to transport through Northern Border or pay for under its Service Agreement. Staff argues that the abatement provision must be evaluated in terms of what it would allow and projects the unit costs of service for various hypothetical volumes of gas which may be transported. Staff argues that the per unit cost for TCPL would be in the general range of that for U.S. shippers when volumes between 200 and 400 MMcf per day of gas are transported through Northern Border, but that, when volumes between 400 MMcf per day to 600 MMcf per day are transported through the pipeline, which is almost 90 percent of the 250 Bcf annual ceiling, TCPL's unit cost of service would be much less than that of the U.S. shippers. TCPL argues that it is improper to base a finding on unit cost of service on hypothetical volumes.

Since we will only allow TCPL to abate depreciation charges when the volumes of gas transported through Northern Border are less than or equal to those that it is required to pay for by its minimum obligation, it is unnecessary to decide whether such a provision would violate Section 4(b) of the Natural Gas Act if throughput volumes reached levels between 400 MMcf per day and 600 MMcf per day. TransCanada cannot object to this result because it introduced evidence that it intended to ship fewer volumes of gas through Northern Border than required by its minimum obligation. 47/ This result is also more consistent with the logic of staff's argument than total elimination of the abatement provision would be. Staff argues that, because the rate charged TCPL would be unduly preferential when throughput reaches 400-600 MMcf per day, the abatement provision should be totally eliminated. It would be illogical to require that the provision be eliminated when throughput volumes are in the 200-400 MMcf per day range simply because the rate become unduly preferential when volumes exceed these levels.

Because TCPL's unit cost of service during the abatement period will only be comparable to that of U.S. shippers if depreciation charges are abated, we believe the difference in rates is not unreasonable. TCPL has demonstrated that the

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47/ *See* TCPL's reply brief at 11-12.

difference in rate treatment is justified by the differences between its Service Agreement and the Service Agreements of the U.S. shippers and by the unit costs reflected in the above table (on page 38) which indicates that TCPL, as a result of its obligation to pay for gas based on specified volumes regardless of whether any gas is shipped, would have a higher unit cost of service than U.S. shippers if depreciation charges were not abated.

The abatement provision does not create an undue preference for another, although less important, reason. If depreciation is not abated, the unit of throughput method of depreciation we are allowing will permit the pipeline to be depreciated over 15 years. If depreciation is abated, this period could be extended to up to 21 years. When Alaskan gas flows, the pipeline is expected to be in operation for at least 30 years. If, the on the other hand, Alaskan gas does not flow by the tenth contract year and it has not been determined that the Alaskan segment will be constructed, TCPL is required to purchase the pipeline at its net value. In that case, its customers will pay in later years whatever depreciation charges they did not pay in earlier years. Thus, whether or not Alaskan gas flows, the abatement provision serves to partially spread the accrual of the depreciation expense or costs over a greater period of time, and a potentially larger number consumers. 48/

We emphasize that our approval of the abatement provision, as modified, is based upon the peculiar set of facts before us and does not establish a precedent which would be applicable to different factual situations.

48/ It could be argued that the result we reach, which allows only TCPL to abate depreciation charges also establishes an undue preference. We believe the same considerations which justify different rate treatment for TCPL during the years when depreciation is abated from shippers using Northern Border in other years also apply when TCPL and other shippers are using the system during the same year.

d. Need for Additional Gas

It seems apparent from a review of the evidence and the briefs in this phase of the proceeding that at least the equity sponsors of the Northern Border prebuild project require additional commitments of throughput volume in order to honor the provisional undertakings upon which the financing is proposed to be structured. 49/

The Commission is not persuaded by staff's argument 50/ that only 1.75 Tcf of throughput for the first six years is

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49/ The position of the lenders on this point is not clear. The Summary of Terms, submitted for the record as Exhibit NB23-A, includes as conditions precedent:

> "2) Granting of NEB export licenses covering at least 1.75 Tcf through December 31, 1987, ...to shippers who have contracted to ship through or pay Northern Border Pipeline Company."

and "5) Evidence of gas transmission service contracts with Northern Border Pipeline Company covering:

> "(a) Licensed export volumes of at least 1.31 Tcf during initial six years of operation, and ..."
>
> (Exhibit NB23-A at 4-5.)

The NEB'S December 6, 1979 export decision granted the Pan-Alberta shippers export licenses for 1.31 Tcf during the period November 1, 1981 through 1987.

50/ See TCPL's reply brief at 17-22. The lender's requirement is that the outstanding balance of the loan at maturity (9 3/4 years after operations commence) be no more than 40 percent of its initial value. As the loans are to be amortized with 70 percent of the cash flow from depreciation plus deferred taxes, a little over 2 Tcf of contracted throughput is required to reduce the loan balance to that level.

(footnote continued on next page)

required to satisfy all of the parties involved. The Commission believes that additional throughput for TCPL's account is at least desirable, if not essential. While not as impressed by the risks TCPL is assuming as TCPL seems to be, 51/ the Commission recognizes the constraint imposed by the lenders' requirement about the size of the loan balance at maturity, and recognizes that TCPL's operating flexibility will be reduced, and perhaps its various agreements with the Canadian Federal Government affected, if it must shift its own volumes during the operating phase from its Canadian facilities to Northern Border.

The Commission does not presently have pending before it either applications or a record upon which to approve additional imports of gas from Canada for transportation through the Northern Border segment of the ANGTS. If the project sponsors are able to arrange financing for the Northern Border prebuild segment based on the import volumes approved herein, this order confers on the sponsors all of the certificate authority necessary to proceed with the construction and operation of that segment based solely on those volumes. Alternatively, if the lenders or investors are unwilling to proceed on that basis, and if the project sponsors succeed in obtaining the requisite regulatory approvals (from the NEB as well as from this Commission) to import additional volumes of gas sufficient to satisfy the lenders and investors, this order confers on the project sponsors all certificate authority to proceed with the construction and operation of that segment premised on such additional volumes.

To summarize, this order does not grant Section 3 import authorization for any volumes of gas to be imported from Canada (or exported back to Canada) other than the volumes specifically

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50/ (footnote continued from previous page)

The 2 Tcf requirement could be met by the 1593 Bcf of Pan-Alberta shippers' gas (1314 Bcf authorized in December, plus 279 Bcf currently applied for) for the first six years plus TCPL's ship-or-pay volumes during the next four years (550 Bcf). However, because of the possibility of low throughput rates during those years, it it is this period for which TCPL seeks abatement of depreciation charges.

51/ See the discussion of these risks in TCPL's reply brief at 22-23, and compare with our discussion of the risks we believe TCPL faces, at footnote 19, supra.

identified and approved in the ordering paragraphs of this order. Those are the only volumes for which the Commission has received import (or export) applications pursuant to Section 3 of the Natural Gas Act. 52/ This order does, however, confer on the project sponsors full Section 7 certificate authority to construct and operate the Northern Border prebuild segment (as described herein) either (a) in the event that the project sponsors obtain regulatory approval to import whatever additional volumes are necessary to secure the financing, or alternatively, (b) in the event that the project sponsors succeed in obtaining that financing without obtaining any such additional volumes.

In an effort to expedite any further proceedings required, the Commission offers the following observations and interpretations which seem appropriate on the basis of the present record. First, the Commission recognizes that TransCanada's ability to ship gas through Northern Border constitutes an integral part of the arrangements approved herein. Also, to the extent that such gas is technically imported into the U.S., transported through Northern Border, and then exported back to Canada, that combined import and export does not raise the significant policy issues that would be raised by either an import or an export standing alone. Accordingly, although specific applications will be required, the Commission by this order, and based on the record before it in this proceeding, approves in principle the import and export of gas that originates in Canada, traverses the Northern Border pipeline, and is then shipped back into Canada, to the extent necessary to effectuate the agreements described herein between TransCanada and the other project sponsors.

Second, while we agree with TCPL that the TCPL Service Agreement provides for the shipment of gas for TCPL's account by parties other than TCPL, and that such volumes could be credited toward TCPL's backstop obligation, 53/ we do not agree with staff that

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52/ Pursuant to the mandate of ANGTA, the Commission would of course consider any such applications on an expedited basis, but it cannot approve such imports absent applications and a record. Such applications, and authorizations granted pursuant to them, would *inter alia* identify the exporters, importers, shippers and transporters with respect to each volume of gas to be imported or exported.

53/ TCPL reply brief at 26. The relevant provision of the TCPL Service Agreement is Article 1(b), *Minimum Obligation*, at the last paragraph of Original Tariff Sheet No. 410.

> "[I]f Alaskan gas came on stream thereafter, TransCanada would only be obligated to pay for the largest volumes it, TransCanada, had actually shipped through the line." (Staff initial brief at 32.)

In our view the TCPL Service Agreement provides for the continuing throughput obligation at the highest level of throughput shipped by any person or persons under the TCPL Service Agreement. Our willingness to accept the proposed abatement provision is expressly conditioned on this interpretation, as it is the continuing throughput obligation that resolves for us the equity questions raised by the abatement provision.

Finally, the Commission wishes to be clear about the relationship of any additional throughput volumes to the economic life of the Northern Border prebuild project as determined herein. As discussed above, the economic life of the project is defined by the various agreements as 4.164 Tcf, derived from 800 MMcfd for 15 years at a 95 per cent load factor. Although TCPL may substitute other persons to discharge its obligations under the TCPL Service Agreement, its ability to do so is limited to the post-Pan-Alberta period when the 800 MMcfd design throughput capacity is not allocated to currently committed export volumes. If, in any year, throughput capacity is increased, or if export or other volumes are contracted and authorized to be put through the prebuild facilities for a period which extends beyond the period contemplated by the agreement between TCPL and the other Northern Border partners (15 years plus extensions in the event of depreciation abatement), the Commission would be obliged to revise the total quantity of contracted throughput (4.164 Tcf) which defines the economic life of these facilities. Such a revision is the approach we took in authorizing certain ANGTS Western Leg facilities earlier this year, 54/ and we believe that approach would be required for Northern Border.

e. Timing and Adjustment of Depreciation

The trial staff has proposed that the Northern Border depreciation rate be adjusted when construction commences on the Alaska segments of the ANGTS. This timing for revising the depreciation rate to reflect anticipated Alaska volumes is set forth in the Commission's Western Leg order, where the Commission found that:

> "This provision will assure consideration of Alaskan gas for depreciation purposes at the

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54/ Western Leg order at 40-41.

> earliest reasonable time..."
> (Western Leg order at 41)

The sponsors of the prebuild project contend that there are several unique factors that make such treatment inappropriate for the Eastern Leg. They argue that the depreciation rate for Northern Border should not be adjusted until Alaska gas flows. In particular, they cite the requirements of the TCPL backstop obligation and its Service Agreement. As TransCanada explains in its initial brief (at 18-19):

> "Adjusting the NB depreciation rate when construction begins in the Alaskan segment of the ANGTS would also expose TCPL to additional risk since under its Service Agreements TCPL is required to maintain its backstop obligation until the earlier of the commencement of Alaskan Gas shipments from Prudhoe Bay through NB or recovery of the investment in the NB pre-build projects...
>
> "TCPL's obligation to provide a backstop for NB is specifically conditioned on the approval of the depreciation methodology for the NB project set out in the First Supplement. This methodology requires depreciation to be charged on a unit of throughput basis predicated on a total throughput of 4.164 Tcf. Provision for modification of this depreciation methodology at any time during the effectiveness of TCPL's backstop obligation would undermine TCPL's willingness to undertake the throughput guarantee. Adjustment of the NB depreciation rate prior to the commencement of Alaskan gas shipments would represent such a modification, effectively transferring to TCPL a portion of the risk which TCPL was unwilling to accept when it agreed to undertake the throughput guarantee. In addition, the premature adjustment of the depreciation provisions would not conform with the requirements of the banking syndicate."

The Commission recognizes sponsors' interest in minimizing financial exposure, but we are not persuaded by the sponsors' arguments. The record does not indicate a strong likelihood or a high risk of non-completion of the ANGTS once construction of the Alaska segment commences nor do the sponsors provide such a risk analysis. Therefore, and for the reasons stated in the Western Leg order, we will require Northern Border to file appropriate revisions of its tariff so as to base its depreciation rate on Alaskan volumes once construction of the Alaskan segments has commenced.

f. Payback Provision

Staff proposes that if Northern Border's depreciation proposal is adopted, the prebuild shippers shall be paid back the excessive cost-of-service charges (paid as a result of the application of Northern Border's accelerated depreciation method) when the depreciation rate changes to reflect Alaskan volumes. While Northern Border states it will file tariff revisions in the future to effect an allocation of excess charges between the prebuild and Alaskan shippers, it opposes staff's payback proposal.

In the Western Leg order, the Commission determined that PGT's costs of new facilities should be rolled-in (i.e., charged to both existing customers and the new customer, PIT) and payback would not be required, since PGT is an existing company with existing facilities and customers. Staff contends that, since there are no existing customers, Northern Border's costs cannot be rolled-in, and that the need for a payback provision is especially compelling because the identity of the prebuild shippers may be substantially different from that of the Alaskan shippers.

As stated in its Western Leg order, the Commission is aware that a goal of regulation is matching of costs incurred with benefits received by specific consumers. That goal is difficult to achieve in the instant matter wherein facilities to be used by two sets of customers are constructed early for use by one of them. Such a situation presents cost allocation problems between two separate periods of time as well as among different groups of consumers.

Considering the above differences, the Commission is aware that there are mechanisms by which the Commission could more precisely match benefits and costs of Northern Border. The Commission recognizes, however, that there are occasions when the equitable advantages of a high degree of matching of costs and benefits to specific consumers are not material enough to justify the implementation of the mechanism. This results primarily from the amount of costs involved and inconvenience, and this is one of those occasions. The Commission therefore does not consider a payback provision necessary in this instance.

III.B. Net National Economic Benefit

In Phase II of this proceeding staff conducted a cost-benefit analysis of the entire prebuild project. Staff assessed the economic benefits of the project from the standpoint of the customers of the Alberta gas and from the standpoint of the nation as a whole. The economic analysis for the nation as a whole is designed to demonstrate the Net National Economic Benefit (NNEB) of the prebuild project. The term "NNEB" is defined in the President's Decision (at 174) as follows:

> "The NNEB measures the desirability of a project from the public perspective. The NNEB of a project is the present value of the benefits derived less the present value of the resources employed in undertaking the project."

The staff used two sets of assumptions for its analysis. Under one scenario (optimistic) the sponsors would receive all of the gas requested (292 Bcf per year for 12 years). The other set of assumptions (pessimistic) projects exportable gas volumes to be 200 Bcf for eight years on an annual basis. Under the pessimistic set of assumptions, the staff economist concluded that for the nation as a whole there will be a negative NNEB of approximately $1.3 billion if only Alberta gas flows through the Northern Border facilities. The negative NNEB would be reduced to between $250 million and $275 million on the Eastern Leg if Alaskan gas deliveries begin on schedule.

Under optimistic assumptions there would be a positive NNEB to the nation as a whole, even if no Alaskan gas flowed through the Northern Border facilities. A much greater positive benefit would result under this scenario if Alaskan gas flows on schedule.

The sponsors conducted their own study and found a positive NNEB to the nation as a whole from prebuilding. According to the sponsors, staff's study grossly understates the benefits of prebuilding because of erroneous assumptions concerning the cost and availability of alternate fuels, and the costs of alternative systems for delivering the Alberta gas. The sponsors contend further that the staff's economic study of the prebuild project is of limited value because there are too many variables. According to the sponsors, such a study should not be used as a basis for a decision as to whether prebuilding should be approved.

We note that the ANGTS project was determined at the time of the Decision to have significant and positive NNEB. A principal assumption in that analysis was a price for imported oil of $14.50 per barrel in mid-1977 dollars. (Decision at 175) Unless the capital costs of the production and tranportation facilities have increased since that time faster than world oil prices, the NNEB of the full project is now significantly larger than it was at the time of the Decision. The more oil prices increase, the higher will be the magnitude of the entire project's NNEB.

The Eastern Leg of the prebuild project has been found herein to be necessary and related to the entire ANGTS. We have also found that its construction will produce tangible benefits to the entire ANGTS. In view of this relationship we believe that there is sufficient justification to conclude that the Eastern Leg prebuild project will have a "significant and positive" NNEB.

III.C. Gas Supply and Market

Because the same underlying contracts support the gas supplies for the Western and Eastern Legs of the prebuild project, the gas supply issue was addressed in the Western Leg order. The briefs of the parties in that phase of the proceeding had considered this issue in terms of the Pan-Alberta/Northwest Alaskan contracts for both the Eastern and Western Legs. Based upon the evidence of record, the Commission concluded in the Western Leg order that Pan-Alberta's gas supply is adequate to support its gas sales contracts with Northwest Alaskan. None of the parties addressed this issue in their briefs on the Eastern Leg, and we affirm herein our prior conclusion that Pan Alberta's gas supply is adequate to support its contracts with Northwest Alaskan.

Evidence of market need was submitted by Northern Natural, Panhandle, and United and ANB. Panhandle and United allege that the Pan-Alberta volumes are necessary to meet the requirements of existing customers. Panhandle points out that between 1970 and 1978 it acquired an average of only 248 Bcf of new domestic gas reserves annually while depleting its reserve inventory by over 557 Bcf per year. Panhandle contends that if the projected Alberta volumes do not come on stream, it could have a shortfall within the next two or three years. Panhandle notes that Residential and Commercial requirements constituted 64 percent of its total system sales in 1978 and that total Priority 5 base period requirements are only 6 percent of its total winter requirements.

Based on this evidence Panhandle asks the Commission to conclude that the Alberta volumes are necessary to meet the high priority gas requirements of its customers.

United argues that as early as 1981 it will be unable to supply its existing requirements from presently contracted reserves. It alleges that the rapid depletion of its committed reserves assures that it will be unable to meet the high priority requirements on its system from those supplies. According to United, Alberta gas can provide a reliable additional volume to its overall systemwide supply, thus reducing the substantial curtailments on its system.

Northern Natural, Panhandle and United jointly presented evidence as to the overall need for and marketability of the Alberta gas. According to a joint study introduced by the foregoing shippers, Alberta gas could compete favorably with alternate fuels in the market areas served by these shippers. The cost of this gas was compared with the projected costs of distillate and residual oil and electricty.

According to staff, the Alberta gas will permit lower priorities to be served longer than they otherwise would. Moreover, staff notes a recent ERA Opinion 55/ which concluded that in most U.S. market areas, the principal alternate fuel is residual fuel oil and that prices for this oil in February 1980 averaged \$3.80 - \$4.00 per MMBtu, well below the Canadian gas price of \$4.47 per MMBtu. 56/ According to the staff, adding a transportation cost of approximately \$1.26 per MMBtu to the Alberta gas price makes this gas less marketable than residual oil.

The Canadian gas price at the time of the hearing was \$3.45. At that price the record indicates that the gas is competitive with the price for the principal alternate fuel, residual fuel oil. Therefore, we find, based on the evidence in the record, that the price of gas will be competitive with alternate fuel at \$3.45 and thus marketable at that price.

55/ DOE/ERA Opinion and Order No. 14, "Order Authorizing On An Interim Basis The Importation Of Canadian Natural Gas At The Newly Established Border Price And Denying Application To Import New Volumes Of Canadian Natural Gas" (issued February 20, 1980).

56/ After the hearing was closed, the price for Canadian gas increased to \$4.47.

IV. PRICE AND CANADIAN GAS IMPORT POLICY

A. Background

The Commission first considered applications for import authority from the sponsors of the prebuild project in the spring of 1978. At that time, the Commission conditionally authorized the imports, 57/ stating:

> "The threshold question of the desirability of importing 1.04 Bcf/d of gas from Alberta has already been answered in the affirmative and needs no relitigation. Of greatest relevance is the holding in the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System, pp. 92-93, that such pre-deliveries from Alberta 'would make gas available over the next few years when the Nation faces serious and immediate natural gas shortages....' This conclusion is completely consistent with the President's assessment of the natural gas shortage through 1990. Id. at 87-91. Such supply and demand conclusions echo those in the El Paso Alaska initial decision, pp. 301-304, which were not changed in the FPC's subsequent Recommendation to the President. Subsequent events have, if anything, supported the President's conclusion. On this basis, the Commission is fully justified in finding that the importation of this additional gas from Alberta through the prebuilt portions of ANGTS is in the public interest. Conditional import authorization is therefore granted." (June 7, 1978 order at 4) (Footnotes omitted)

The Commission's reservations included one with regard to:

> "...any possible future change by Canada of the present border price of $2.16 per Mcf (sic) at which this gas would be sold to Northwest Alaskan ...;" (June 7, 1978 order at 5)

57/ "Order Granting Intervention, Establishing Intervention Procedures for the Overall Alaska Gas Proceeding, and Granting Conditional Import Authorization," Docket Nos. CP78-123, et al. (issued June 7, 1978).

There have been a number of increases in the Canadian border price since that time, as evidenced by the following table, taken from a recent order of the Department of Energy's Economic Regulatory Administration (ERA). 58/

Export Price	Effective Date
$1.00/MMBtu (CA)	November 1, 1974
1.60/MMBtu (CA)	November 1, 1975
1.94/MMBtu (CA)	January 1, 1977
2.16/MMBtu (US)	September 21, 1977
2.30/MMBtu (US)	May 1, 1979
2.80/MMBtu (US)	August 11, 1979
3.45/MMBtu (US)	November 3, 1979
4.47/MMBtu (US)	February 17, 1980

Until the most recent increase, the pace of advance in the prices of alternative fuels had been such that the price of Canadian gas had remained within the competitive range of prices charged for those fuels in the U.S. market areas where Canadian gas comprised some part of system supply. In early January, the Commission was able to find, with regard to the proposal to prebuild certain segments of the Western Leg of the ANGTS,

> "...we believe that the price paid for this gas is reasonable when compared to the price of alternative fuels and that there are sufficient economic benefits associated with this project so as to justify its approval... We conclude that the importation of the proposed volumes at the [then] prevailing border price would be in the public interest." (Western Leg order at 28)

Similarly, for the Eastern Leg prebuild project, the increased price of Canadian gas had, until the most recent increase, stayed within the range of comparable prices of alternate fuels. As discussed above, we have concluded that the gas could be sold if the border price was $3.45 per MMbtu. Other parties, principally the staff, expressed some concern regarding the priority of the customer classes who would likely utilize the gas supplies to be delivered by this project, but did not suggest that the gas would be unmarketable at a border price of $3.45.

58/ DOE/ERA Opinion and Order No. 14, supra.

Subsequent to the receipt of evidence on this issue, the border price was raised to $4.47 per MMbtu. 59/ Rather than reopening the record in that phase of the proceeding in light of the new border price, the Presiding Administrative Law Judge instructed the parties to use the new price in briefing the issue to the Commission. 60/

On the day before the effective date of the new price, ERA issued an order approving on an interim basis the continued importation of flowing gas at the new price, but denying certain applications for new import authority. 61/ In that order, ERA observed (at 5-8) that the Canadian Government had for some time utilized a formula for establishing the border price for gas sales to the U.S. which tied that price to the cost of crude oil imported into eastern Canada. ERA noted, however, that the application of the formula had previously produced a result which was consistent with the alternate fuels criterion utilized by ERA, 62/ and more recently by the Commission, 63/ to determine whether a proposed import is in the public interest. ERA went on to state that, for the most recent increases, there had been a change in the application of the formula which had taken the new price outside the competitive range. As finding the price within that range had been the test which ERA had applied to find the import in the public interest, ERA approved the continued importation of flowing gas supplies only on an interim basis, pending a comprehensive review of the terms and conditions under which Canadian natural gas may continue to be imported into the U.S. at the new price. ERA's order provided for the development of a full administrative record on the question of appropriate terms and conditions for the importation of Canadian gas, with a decision to be issued prior to the expiration of the interim approval on May 15, 1980.

59/ National Energy Board of Canada, "Report to the Governor in Council in the Matter of the Pricing of Natural Gas Being Exported under Existing Licenses" (January, 1980). This report was approved by the Governor in Council (the Canadian Cabinet) on January 21, 1980, and the new price went into effect on February 17, 1980.

60/ Tr. 101.

61/ DOE/ERA Opinion and Order No. 14, *supra*.

62/ *See* note 8 to DOE/ERA Opinion and Order No. 14.

63/ Western Leg order at 28.

Subsequent to the issuance of that order, the Secretary of Energy met with appropriate officials of the Canadian Government to discuss the question of establishing the border price for Canadian natural gas. By letter dated April 24, 1980, the Secretary formally advised the Commission of those discussions, and of the Canadian Government's agreement to a mechanism for determining the border price. A copy of the Secretary's letter, enclosing an exchange of letters between him and the Canadian Minister of Energy, Mines and Resources, is attached to this order.

IV.B. The Exchange of Letters in the Context of Regulatory Requirements

The Secretary's letter to the Canadian Energy Minister, dated March 26, 1980, expresses his support as a matter of policy for the mechanism established by the Canadian Government, "... to the extent that the pricing mechanism...meets our regulatory requirements." In his letter to the Commission, the Secretary stated:

> "While this mechanism does not absolutely guarantee a competitive relationship between Canadian gas prices and alternative fuel prices in the U.S. markets, it substantially increases the likelihood that such a result will occur, ..." (Letter at 3)

As discussed above, the Commission, as well as ERA, has used an alternate fuel criterion to determine whether a proposed import is consistent with the public interest. The Commission considers the Secretary's communications both to the Canadian Energy Minister and to the Commission as supportive of the continued relevance of that criterion, and interprets the Secretary's policy support subject to regulatory requirements as an expression of his view that imports of Canadian gas are generally in the public interest when the Canadian pricing mechanism yields a result which is consistent with the alternate fuels criterion.

The Commission believes that ERA's findings in Opinion and Order No. 14 are relevant to the Commission's consideration here. Although ERA was not able to find that the proposed $4.47 per MMBtu border price was consistent with the public interest on the basis of the alternate fuels criterion, it was able to approve an interim continuation of flowing gas imports on the basis of the existing reliance on the gas. 64/ This interim finding was made pending a more complete evaluation of the relationship of the new price to that of alternative fuels in the markets where Canadian gas competes, and pending specification of appropriate terms and conditions to govern continued Canadian gas imports in view of that relationship.

The Commission believes that a similar consideration is appropriate here. In light of the importance of constructing the full ANGTS, and the relationship of the prebuild to that objective (as discussed elsewhere in this order), the Commission has concluded that, subject to certain conditions as discussed below, and for an interim period pending completion of ERA's policy review, importation of the Canadian gas at issue herein would not be inconsistent with the public interest at the present Canadian border price of $4.47 per MMBtu. That conclusion, however, is premised on the assumption that the gas imported in connection with the prebuild would not be more expensive than other imports of gas from Canada, i.e., that the $4.47 import price for the prebuild project gas will not exceed the highest import price approved by ERA with respect to other imports of natural gas from Canada.

As noted above, we anticipate that on or prior to May 15, 1980 the Administrator of ERA, as the Secretary's delegate, will issue an order determining the maximum acceptable import price for such other Canadian gas imports. The interim authorization granted herein will become final at the approved price when the Administrator of ERA issues her order specifying the terms and conditions under which Canadian gas may continue to be imported into the U.S at that price through facilities and in implementation of approved import projects other than the ANGTS prebuild. In the event that the Administrator does not approve the importation of any natural gas from Canada at a border price of $4.47, then the import authorization granted herein will be further limited by a condition that the price of the gas to be imported in connection with the prebuild of the Northern Border segment be adjusted downward to the highest price for imported Canadian gas approved by the Administrator of ERA.

64/ DOE/ERA Opinion and Order No. 14 at 5-8.

IV.C. Conditions Governing Import Authority for the Prebuild Project

Special consideration is required to determine appropriate terms and conditions to govern importation of Canadian gas as part of the prebuild project because of the urgent national priority associated with implementation of the complete ANGTS. The Secretary of Energy's letter to the Commission (at 2) requests early action on these terms and conditions in order to maintain the current project implementation timetable, calling for commencement of gas deliveries in the fall of 1981.

In considering appropriate conditions to govern gas imports for the prebuild project, the Commission observes that the pricing mechanism established by the Canadian government retains the crude oil substitution value concept which has been a feature of Canadian gas pricing for some time. 65/ As

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65/ See "Statement of Principles on Canadian Gas Export Pricing," enclosed with the letter, dated March 25, 1980, to Secretary Duncan from the Honorable Marc Lalonde, Minister of Energy, Mines and Resources for the Government of Canada, forwarded to the Commission by the Secretary and attached to this order.

The previous method for establishing the border price of Canadian gas is described in National Energy Board, "Report to the Governor in Council in the Matter of the Pricing of Natural Gas Being Exported under Existing Licenses" (January, 1980), especially at pages 1 - 5.

The principal difference between the two regimes is in certain adjustments applied to the landed cost of crude oil in Canada. An element of the prior formulation, adding a transportation charge from the port of entry to Toronto, has been replaced by an "adjustment factor," initially equal to 22 cents (U.S.) per MMBtu, to be determined from time to time by Canada's Governor in Council. The 22 cents per MMBtu is stated to be "... the transportation adjustment implicit in the existing U.S. $4.47 border price." (Statement of Principles at 1) The Statement of Principles does not specify the circumstances under which the adjustment factor might change.

discussed in the ERA order mentioned above, application of that concept had, until the most recent price increase, yielded a result which was acceptable under an alternate fuels criterion for determining whether the import was consistent with the U.S. public interest. Only for the last increase did the extraordinary pace of increases in world oil prices, combined with a reduction in the lag between the time of the oil price increases and the time those increases were reflected in a higher border price, result in a border price which did not meet the alternate fuels test.

The pricing mechanism established by the Canadian government is intended to restore a lag of 90 days between the measurement of the substitution value of Canadian gas, according to the adjusted cost of Canadian oil imports, and reflection of that value in the border price. As this 90 day lag approximates that which was inherent in the price mechanism applied prior to the most recent increase, we could expect that, as a general matter, the prior relationship to alternate fuel prices in the U.S. would be restored.

Exceptions to this general expectation may arise when petroleum product price trends do not follow the trend for crude oil prices. Such exceptions can be due to seasonal factors, changes in the level of economic activity, imbalances among stocks of various products due to refinery runs or shifts in demand, or combinations among these factors or with others. Because of these factors, and because of conservation effects at higher prices, there may be periods when crude oil prices are rising, but fuel oil prices are stable, or even declining. During such periods, the relationship between crude oil prices and the border price of Canadian gas could result in a temporary movement of the Canadian gas price out of the acceptable range, particularly in certain markets.

The Commission believes that the proper regulatory framework for these imports would allow the U.S. purchasers of the gas to reduce the level of their purchases as necessary to reflect the impact of competition with alternate sources of fuel supplies and the effects of conservation at higher prices. Such a framework would increase our expectation of a competitive relationship between Canadian gas prices and alternative fuel prices in U.S. markets by introducing an element of self-regulation into the importation of Canadian gas and by allowing the recipients of this gas to more precisely match supply with demand.

Certain elements of the prebuild projects as proposed would appear to constrain the ability of the U.S. participants in the projects to respond to market signals. Of particular concern to this Commission and to the Secretary of Energy are certain features of the gas supply contracts between Pan-Alberta and Northwest Alaskan, which contracts serve as the basis for the prebuild projects. (See the attached letter from the Secretary to the Commission at 2-3.) The features at issue are the minimum daily and minimum annual take provisions, Articles IV.A.3. and IV.A.4. of the contracts, which provide that the purchaser must take not less than 50 percent of the contemplated daily quantity on any given day, and not less than 85 percent of the contemplated annual quantity during any contract year. 66/ These features appear to be inconsistent with a framework which provides the purchasers of the Canadian gas with the ability to reduce their purchases during periods when that gas is not competitive with alternate fuels.

These contract provisions have the effect of committing the U.S. purchasers to taking a very large proportion of the gas made available under the contracts without regard to its price relationship to other sources of fuel supplies. At the current border price, the obligation in Article IV.A.4. would require the U.S. purchasers to find a market for Canadian gas worth over $1.1 billion per year, regardless of the prices of alternative fuels. As characterized by the Secretary of Energy, these provisions "...could create an unreasonably large artificial market for Canadian gas in this country" (Letter at 3). In view of our alternate fuels criterion for determining the acceptability of a particular source of imported gas supply, the Commission does not believe that these provisions as they now stand provide an acceptable basis for finding that the proposed imports are not inconsistent with the public

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66/ These features are picked up and repeated in Northwest Alaskan's contracts for resale of the gas to the U.S. shippers. The Commission's concern about these provisions, and our conditions to alleviate those concerns, are intended to apply to and limit the provisions of the contracts for resale in the same manner that they apply to the basic contracts.

interest within the meaning of Section 3 of the Natural Gas Act. 67/

"Take-or-pay" provisions in sales contracts between producers and shippers of gas, of which the provisions in the Pan-Alberta contracts are a variation, 68/ have traditionally been included when substantial investments in production, gathering and transportation facilities are required for commencement of gas deliveries. Such provisions are used to ensure the integrity of the revenue stream, from gas consumers

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67/ These provisions are made especially difficult for U.S. importers by conditions of the export licenses granted by the NEB. The obligations to take the gas are open-ended with regard to future increases in the border price. Additionally, the licenses do not allow the importers to defer taking gas until market conditions have improved (*i.e.*, there is no provision for "make-up" of gas paid for but not taken). (See the NEB's export decision at 9-2.) Finally, the licenses constrain the importers' ability to accommodate market factors by varying their rates of take. The latter constraint is imposed by limiting maximum day takes to approximately 112 percent (110 percent authorized plus 2 percent tolerance) of average day takes. (See the license conditions in Appendix H to the NEB's export decision.)

68/ The classic "take-or-pay" provision provides that the purchaser will pay for a certain minimum specified quantity of gas at a specified price regardless of whether or not he takes the gas. Such provisions are usually accompanied by so-called "make-up" provisions, which allow a purchaser to take without charge in a subsequent year gas which he has paid for in a prior year but was unable to take.

The provisions in the Pan-Alberta contract are a variation on the take-or-pay theme. The Pan-Alberta provision obligates the purchaser to take a specified portion of the contracted-for quantities regardless of market conditions. Because of the wording of the provision, which says "...Buyer shall request and take and pay for ..." (Article IV.A.4.), these provisions are referred to as "take-and-pay" provisions.

through owners of transportation facilities to gas producers. This revenue stream then provides a basis for financing both production and transportation facilities, if necessary.

In the case of the Eastern Leg prebuild project, the nature of the tariff treatment afforded to both U.S. and Canadian segments of the ANGTS offsets the requirement for take-or-pay-like provisions in order to finance the transportation facilities. The Commission has approved a cost-of-service-type tariff for the transporter in the U.S., including a service agreement with the shippers that provides for payment of transportation charges on a "ship-or-pay" basis. 69/ In another section of this order, tracking provisions for the shippers' tariffs are approved which provide for recovery by the shippers in their rates of charges paid to Northern Border, also on a basis which is independent of throughput volumes. The NEB has provided comparable tariff treatment for the Canadian transporter. Foothills (Yukon) has a cost-of-service tariff, and shippers on the Foothills system are obliged to pay their proportionate share of Foothills's cost of service, regardless of how much gas they are shipping, based upon the contracted-for throughput volumes. Again, as is the case with the U.S transportation facilities, the obligation of the Canadian shippers to their transporter is independent of volumes actually shipped. Thus, the integrity of the revenue stream which forms the basis for financing the transportation facilities for the Eastern Leg prebuild project in both the U.S. and Canada is unaffected by variations in throughput. 70/ This assurance obviates the requirement for any take-or-pay-like provisions in order to finance the transportation facilities.

69/ Orders Nos. 31 and 31-B. Northern Border's service agreement provides for billing according to contracted-for throughput capacity, rather than according to actual throughput. Northern Border's revenues are only reduced when it is unable to perform, and even then its revenues are never reduced below the level provided by the minimum bill.

70/ An exception to this generalization can be conceived in the event that gas volumes shipped through the transportation facilities in Canada fall so low that total revenues derived from sales of the gas at the border are

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Although transportation system revenues are assured essentially independent of throughput, certain production-related facilities may also be required as part of the complete prebuild project, and those facilities are not afforded the security of a ship-or-pay service obligation. To the extent that producers must invest in gathering and conditioning facilities in order to make gas available to the pipeline system, 71/ financing of those investments is also likely to require some assurance of a revenue stream. The Commission can understand a requirement for some type of take-or-pay protection for the Canadian producers participating in the prebuild project.

Prior gas supply contracts for imports of Canadian gas have included take-or-pay provisions. However, with only

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70/ (footnote continued from previous page)

inadequate to cover the cost of service of the transportation facilities. At a border price of $4.47 per MMBtu, the Commission estimates that throughput would have to fall below approximately one-eighth of the level contemplated for the Eastern Leg before the revenue stream for the transportation facilities would be jeopardized.

The Commission considers such a situation exceedingly unlikely. For throughput to fall to this degree, the border price would have to be significantly out of line with the prices of alternate fuels. We do not believe such a disparity would be the intention of the Canadian authorities with responsibility for establishing that border price. We expect that under the mechanism referred to in the exchange of letters between Secretary Duncan and Minister Lalonde, the border price will remain generally competitive with alternate fuels.

71/ The gas to be exported as part of the prebuild project was awarded export licenses under the NEB's Current Deliverability Test for exportable surplus. *See*, the NEB's export decision at Chapter 9. As this test is based on deliverability from established reserves (see the discussion of the NEB's procedures for determination of exportable surplus in National Energy Board, *Canadian Natural Gas - Supply and Requirements*, Cat. No. NE 23-10/1979 (February, 1979) at Chapter 5), the Commission assumes that no field development expenditures are required as part of the project.

two exceptions involving interstate pipelines, 72/ these provisions consist of a demand charge and a commodity charge according to a schedule provided in each contract. The present commodity charge under a Northwest schedule, for example, is 28 cents per Mcf. Thus (with only the two exceptions), the producers essentially spelled out in their gas sales contracts what revenues they needed to finance gathering and conditioning facilities. 73/

The Commission can accept that the Canadian producers have a legitimate requirement for an assured cash flow. By way of analogy to the role of the ship-or-pay obligation between the shipper and the transporter in obtaining financing for the transporation system, the Canadian producer needs to establish what amounts to an accounts receivable from U.S. importers at an assured minimum value. Like the transporter, the producer needs from his customers an unconditional obligation to pay sufficient to enable him to attract financing. However, although the Commission can understand the producers' requirement for an assured revenue stream, we do not believe that financing gathering and conditioning facilities for production of reserves which are already proven requires a revenue stream which escalates with the cost of Canadian oil imports. Our concern is that the "takeand-pay" provision as structured in the proposals before us goes considerably beyond provision of an assured minimum cash flow to the producers. If the cost of Canadian oil imports increases, a requirement to take a guaranteed minimum amount of gas regardless of future price increases seems likely to result in "windfall" gains to the Canadian producers unrelated to any legitimate economic requirement.

72/ The exceptions are two contracts which Alberta and Southern, and Westcoast, have with PGT and Northwest, respectively, for exports through PGT's facilities beginning at Kingsgate, British Columbia. These contracts have minimum bill provisions which provide that the importers will pay for the Canadian pipeline's cost-of-service and for any take-or-pay obligations which the Canadian pipelines incur with the Canadian producers.

73/ Given the fact that the current Canadian export price is a fixed, one-part rate per Mcf taken, the continued applicability of take-or-pay provisions in all these contracts is unclear.

The Commission believes that the most reasonable approach to providing Canadian producers with an assured minimum revenue to support financing of required facilities, while at the same time limiting the exposure of U.S. purchasers of the imported gas, would be to limit the take-or-pay-like obligation to a fixed amount of money per day or per year, as appropriate. Rather than specify that the U.S. purchasers must take and pay for minimum quantities of gas, the Commission's alternative would specify that they would have to take and pay for enough gas to provide an assured minimum amount of revenue. In this way, assuring the producers' cash flow requirements would not come at the expense of an open-ended obligation on the part of U.S. purchasers.

Under this modification, the obligation of the U.S. purchasers to take gas would go down if the border price went up. However, the purchasers would always be obliged to take enough gas to provide the established minimum revenue. There will be no upper limit to the daily and annual revenues that may be paid by U.S. importers; as long as the gas is competitively priced, the condition to be imposed by the Commission will not interfere with the workings of the gas supply contracts as contemplated when they were signed. Only in the event that the pricing of the gas resulted in its being backed out of U.S. markets would the limits imposed by the Commission come into play. Thus, the condition to be imposed by the Commission effectively assures the Canadian producers of sufficient revenue to finance gathering and conditioning facilities even in the event that the delivered gas is not competitively priced. 74/

74/ The Commission understands that realizations at the wellhead in Canada are determined based on a weighted average netback from domestic and export sales. Thus, although the amount of gas each producer sells is affected by which markets he has access to, the price he realizes per unit of gas sold is a weighted average of the unit prices realized on all sales of Canadian gas, domestic and foreign. Thus, even if revenues from export sales through the prebuild were only enough to cover the cost of service of the pipeline, the producers selling to the prebuild project would realize some cash flow.

The Commission also notes that the agreed pricing mechanism for Canadian gas includes an adjustment for the weighted average transportation cost of export gas. The Canadian border price is allowed to be adjusted as often as monthly in the event that reduced throughput is having a significant impact on that weighted average transportation cost.

The mechanism by which the Commission proposes to implement the limit in this instance is to pick an appropriate value of the border price and multiply it by the quantities of gas specified in the "take-and-pay" provisions of the Pan-Alberta contracts to yield minimum daily and minimum annual amounts of money that Northwest Alaskan, and in turn the subsequent U.S. purchasers of the gas, would be obliged to pay Pan-Alberta. Thus Pan-Alberta would be assured sufficient revenues to finance gathering and conditioning facilities; Northwest Alaskan, on the other hand, could reduce its gas purchases below the quantities specified in Articles IV.A.3. and IV.A.4. of the gas supply contracts as long as it purchased enough gas to provide the specified minimum revenues.

The Commission believes that this policy, or variations of this policy, could have broad applicability to all proposals to import Canadian or other gas supplies. The Commission commends this policy proposal to ERA's consideration in determining appropriate terms and conditions to govern continued authorization of current and future imports of Canadian gas, and of gas imports from other sources. 75/

The question remains for the Commission to determine what value of the border price provides an adequate annual revenue stream to support investment in requisite gathering and conditioning facilities for the prebuild project. If time would permit, this question is of a type which commends itself to the kind of factual inquiry currently being conducted by ERA. However, time will clearly not permit if the fall, 1981 target in-service date for the Northern Border prebuild facilities is to be met. Thus, pursuant to the ANGTA mandate for expedition, we must answer this question based on the record before us.

We look first to the level of prices prevailing at the time the majority of the producer sales contracts were being executed. Materials filed with the Commission 76/ suggest

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75/ The increase in price to $4.47 occurred subsequent to the issuance of the Commission's Western Leg order. The Commission will consider a similar condition with respect to imports to be transported through the Western Leg when it acts, on rehearing, in that proceeding.

76/ *See*, e.g., the study of reserves and deliverability as of July 1, 1979, filed in Phase II of this proceeding on July 9, 1979. Applications to export were filed in Canada on April 18, 1979, according to the NEB's export decision (page 2-7).

that those contracts were largely concluded during the first few months of 1979, during which time the border price for gas committed to export was $2.16 per MMBtu. The revenue projections and financing plans of the producers could hardly have contemplated the doubling of world oil prices, and the concomitant increases in the border price of Canadian gas for export sales to the U.S., which took place during the latter half of 1979.

The Commission's record in this proceeding supports a determination that the proposed imports would be marketable, and thus not inconsistent with the public interest, at a border price as high as $3.45 per MMBtu. Thus, the impact of the "take-and-pay" provision in the Pan-Alberta contracts can be found to be not inconsistent with the public interest at that level. There is a significant difference in the magnitude of the "take-and-pay" obligation in the Pan-Alberta contracts valued at $2.16 per MMBtu from what it is at $3.45 per MMBtu. Nevertheless, in the interest of supporting initiatives to get the ANGTS started, the Commission is willing to accept a cap on the take-and-pay obligation at $3.45 per MMBtu if doing so would assure early action towards implementation of the project. If the Commission cannot be assured of such early action, it would feel obliged to reopen the record for further study of the level of the border price which would provide sufficient assured revenues to support producer investment in gathering and conditioning facilities.

In the expectation that a cap on the take-and-pay obligation at $3.45 per MMBtu will provide adequate revenues to support producer investment, the Commission adopts the following conditions to the import authorizations provided herein:

1) The Buyer's obligation under Article IV.A.3. of the Pan-Alberta gas supply contracts is limited to U.S. $1,380,000 per day (800,000 Mcf/day X $3.45/Mcf X 50 percent).

2) The Buyer's obligation under Article IV.A.4. of the Pan-Alberta gas supply contract is limited to U.S. $856,290,000 per year (800,000 Mcf/day X 365 days/year X $3.45/Mcf X 85 per cent).

IV.D. Other Pricing Policy Matters

Two other pricing matters must be resolved for the Northern Border prebuild project:

1) Whether the gas to be delivered by the prebuild project is to be afforded rolled-in or incremental pricing treatment when the shippers pass through the cost of this gas to their customers; and

2) Whether the shippers' purchased gas adjustment (PGA) mechanisms in their tariffs should be utilized to pass on any changes in the border price of the Canadian gas proposed to be imported. 77/

IV.D.1. Incremental vs. Rolled-in Pricing

There are two basic methods of allocating costs to be reflected in a utility's rate structure. Under Section 204 of the Natural Gas Policy Act of 1978 (NGPA)(Pub. L. 95-621), the incremental pricing mechanisms would operate to increase prices to certain gas users until the price they pay for their natural gas equals the BTU equivalent price of substitute fuel oil. Rolled-in pricing is a method of ratemaking wherein the cost of new facilities and new gas supplies are collected or rolled-in with the costs of older facilities and gas supplies, for the purpose of determining the cost of gas to the entire system, which is then prorated among all the customers. See Battle Greek Gas Co. v. F.P.C., 281 F.2d 42 (D.C. Cir. 1960)

United and ANB request that the Commission explicitly state that these imports may be priced on a rolled-in basis. United argues that it cannot purchase Albertan gas if, upon resale, the gas is subject to incremental pricing or direct assignment of costs. Although no party objects to United's request on its merits, staff and the New York

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77/ PGA-type pass-through was proposed in the Shipper Tariff Phase of this proceeding, and certain aspects of this question are dealt with below in the section on Shipper Tariffs and Tracking. However, the basic question of whether to provide PGA-type pass-through is dealt with here as a matter of appropriate policy to govern the importation of this gas.

Public Service Commission raise several procedural objections. Staff requests that the Commission defer ruling on the issue until ERA completes its pending review of Canadian gas import policy. Because of the impact of the timing of Commission action on the sponsors' ability to attain the target in-service date, we must reject this suggestion. New York suggests that the question should be resolved in United's pending rate proceeding in Docket No. RP78-68. This request is also denied, as the Commission believes that the important considerations in resolving this question derive more from this proceeding than from United's general rate proceeding.

Title II of the NGPA requires that interstate pipelines and local distribution companies pass through certain portions of their natural gas acquisition costs to industrial users in the form of surcharges. Certain portions of the costs of natural gas imports are subject to this incremental pricing requirement (Section 203). However, the NGPA does not require volumes of natural gas imports to be incrementally priced either (1) if these volumes do not exceed the maximum delivery obligations which are specified in contracts entered into on or before May 1, 1978 and in effect when the gas is delivered, or (2) if the volumes do not exceed the volumes of natural gas imported by the interstate pipeline during 1977 (Section 207 (b)). Under Section 207(c), the Commission or the Secretary of Energy (in accordance with the assignment of functions under the Department of Energy Organization Act) is authorized to determine whether such imports will be subject to incremental pricing.

The contract between Pan-Alberta and Northwest Alaskan for the sale of the gas to be imported into the U.S. was entered into on March 9, 1978. 78/ The maximum delivery obligation under the contract for the Eastern Leg of the ANGTS is 800,000 Mcf per day. Northwest Alaskan is requesting authorization to import this same quantity into the U.S. for transportation through Northern Border. Therefore, the gas proposed to be imported as part of the prebuild project is not required to be incrementally priced, since the volumes to be imported will not exceed the maximum

78/ In its June 7, 1978 order (at 6) conditionally authorizing these imports, the Commission deferred ruling on whether the shippers should use rolled-in or incremental pricing because Congress was considering the question at that time.

delivery obligations specified in the contract, and the contract predates May 1, 1978. However, the volumes imported by Northwest Alaskan under its contract will exceed the volumes which it imported in 1977. Therefore, under Section 207(c) of the NGPA, it is within the Commission's discretion (pursuant of the Secretary of Energy's delegation of authority under the Natural Gas Act 79/) to determine whether these imports should be subject to the incremental pricing provisions of the NGPA.

Where ERA has had the discretion to decide whether natural gas imports should be incrementally priced, it has required incremental pricing. SEE <u>DOE/ERA Opinion and Order No. 11</u>, Dec. 29, 1979; <u>DOE/ERA Opinion and Order No. 12</u>, Dec 29, 1979; and <u>DOE/ERA Opinion and Order No. 14</u>, Feb. 16, 1980. In Opinion No. 11, ERA explained that rolled-in pricing would send low priority users a false signal as to the true cost of incremental gas supplies, and that it would be inconsistent to shield high cost imported gas from exposure to market conditions by permitting it to be rolled in with other pipeline supplies while at the same time the NGPA requires high priced domestic sources of gas to be incrementally priced.

Although the Commission finds ERA's reasoning persuasive in the context of gas imports generally, we view the prebuild project as the first step in implementation of the ANGTS and believe that this consideration is overriding. In this regard, we note that the Congress itself provided for rolled-in pricing for the ANGTS, 80/ to facilitate its financing. 81/ In our view, pricing of the Canadian gas for the prebuild project, which is designed to facilitate implementation of the entire ANGTS, presents an analogous situation.

79/ Section 207(c) provides in effect that the determination will be made pursuant to the NGPA mechanism, and that it will be made by the agency (i.e., the Secretary or the Commission) that would have had the jurisdiction to make that determination if the authority to do so had arisen out of the Natural Gas Act instead of the NGPA. Pursuant to DOE Delegation Order No. 0204-8, <u>supra</u>, the Secretary has delegated to the Commission <u>inter alia</u> all functions under the Natural Gas Act with respect to the prebuild of the ANGTS.

80/ <u>See</u>, Section 208 of the NGPA.

71/ <u>See</u>, particularly, H.R. Rep. No. 95-1752, 95th Cong. 2d Sess., p. 103 (1978).

The Commission has consistently taken the position that regulatory decisions which might serve to contribute to such uncertainty as would significantly discourage financing of the ANGTS are not in the national interest. To subject the prebuild volumes to incremental pricing would place such a cloud on the prebuild project and might increase the cost of financing. For this reason, then, we have determined to allow the prebuild volumes to be priced on a rolled-in basis.

IV.D.2. Mechanism for Pass-Through

As mentioned above, the U.S. shippers have requested use of a PGA mechanism to reflect the costs of the Canadian gas volumes and their transportation through Northern Border in the shippers' rates. In considering this question, the Commission believes that it is important to distinguish between the granting of import authority at a certain border price, which is done pursuant to Section 3 of the Natural Gas Act (NGA), and providing for reflection of the costs of that imported gas in a shipper's rates. Establishing a pipeline's specific rates is done pursuant to Sections 4, 5 and 7 of the NGA, unless pass-through is provided through an automatic or semi-automatic mechanism, such as a PGA mechanism.

The Commission has no objection to providing a PGA mechanism for pass-through of the cost of the gas once an import has been found to be in the public interest at the price for which it is proposed to be introduced into the domestic pipeline system. In fact, we have provided a form of a pass-through mechanism for resale of imports of Mexican gas. 82/ However, the Commission believes that an evaluation for consistency with the public interest should be made each time there is a price change for a particular source of imported gas. As is the case with the Canadian gas import policy review currently in progress at ERA, the Commission would expect that different terms and conditions would be

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82/ Border Gas, Inc. et. al, Docket No. CP80-93, CP80-75 (Phase I) et al., "Findings and Order after Statutory Hearing, Issuing Certificates of Public Convenience and Necessity, Granting Import Authorization, Granting Adjustments and Granting Petition to Intervene" (issued December 21, 1979).

appropriate to govern a particular source of gas imports at different levels of the price for that source. 83/

83/ In the future, it may prove cumbersome to have such reviews conducted simultaneously by two different agencies (ERA and FERC) for gas imports from the same source. Thus, upon completion of all Commission actions to authorize the prebuild projects, including resolution of issues raised on rehearing, the Secretary of Energy may wish to consider an appropriate amendment of DOE Delegation Order No. 0204-8 so as to withdraw his delegation to the Commission of the authority to approve Canadian gas imports associated with the ANGTS.

V. COST ESTIMATES

A. Background

The President and the Congress provided the basic authorization for the facilities proposed to be constructed as part of the Eastern Leg prebuild project pursuant to the provisions of the ANGTA. One of the conditions on that basic authorization was a requirement 84/ that the Commission develop a variable, or incentive, rate of return (IROR) mechanism in order to "...provide substantial incentives to construct the project without incurring [cost] overruns." (Decision at 37.)

The authorization provided by the Decision was based on the very extensive record that had been compiled by the Federal Power Commission (FPC), predecessor to this Commission. That record included estimates of capital costs which had been filed with the FPC on March 8, 1977. 85/

The President and the Congress recognized, however, that the March 1977 estimates would require revision between the time of the Decision and the time of final authorization of the ANGTS facilities by this Commission, at least because of changes in the design of the approved project required by the U.S.-Canada Agreement. 86/ Thus, the authorization granted by the Decision was specifically conditioned 87/ on a finding by by this Commisison in the course of final certification proceedings that the revised estimates do not "... materially and unreasonably exceed ..." the March 1977 estimates. The

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84/ Finance Condition 2 (Condition 5.IV.2.) at pages 36-37 of the Decision.

85/ "Alcan Pipeline Project 48" Alternative Proposal," Docket No. RM77-6.

86/ This change is mentioned in Finance Condition 2, supra. The intention to change the design of the pipeline is covered in paragraphs 3 and 10, among others, of the U.S.-Canada Agreement, at pages 48-49 and 62, respectively, in the Decision.

87/ Finance Condition 2, supra.

Decision also allowed the Commission the option of using the revised estimates, rather than the March 1977 estimates, as the basis for the IROR mechanism that the Commission was required to develop. 88/ The Commission adopted the option of using the revised estimate, referred to as the Certification Cost and Schedule Estimate (CCSE), in its order establishing the IROR mechanism, recognizing that the Commission was authorized by the Decision to deny final certification in the event that it was not satisfied with the CCSE. 89/

In its first IROR order, 90/ the Commission instructed the Alaskan Delegate to work with the project sponsors to develop cost estimate formats for submission of the CCSE's. The Delegate filed a report with the Commission 91/ in August of 1979 regarding the required comparisons between the March 1977 estimate and the CCSE.

The Alaskan Delegates's Report provided specific criteria for formats to be used by the ANGTS sponsors in the submission

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88/ Ibid. The meaning of the language on this point in Finance Condition 2 was the source of some controversy in the course of the Commission's proceedings to develop the IROR mechanism. The Commission provided its interpretation of this language at pages 17-19 of its "Revised Notice of Proposed Rulemaking," Docket No. RM78-12, "Incentive Rate of Return for the Alaska Natural Gas Transportation System" (issued September 15, 1978).

89/ See Order No. 31, supra, at 24-32. The Commission clarified its intentions with respect to the CCSE in "Order No. 31-B on Rehearing," issued in the same docket on September 6, 1979, at 3-8.

90/ Order No. 17, "Order Attaching Incentive Rate of Return Conditions to Certificates of Public Convenience and Necessity," Docket No. RM78-12 (issued December 1, 1978). See especially pages 9-10.

91/ John B. Adger, Jr., "Memorandum for the Commission," dated August 3, 1979 and served on all parties in Dockets No. RM78-12 and CP78-123, et al. That document included a report prepared by James D. McCullough of the Institute for Defense Analyses, "Recommended Cost Formats for Submission by Alaska Gas Pipeline Sponsors to FERC," IDA Paper P-1417 (July 1979).

of appropriate cost estimate materials. In particular, criteria were provided for the information to be displayed for the March 1977 estimate, for the March 1977 estimate repriced in base-year dollars, 92/ for the CCSE, and for comparisons between the latter two estimates.

Specification of criteria for submissions was intended to assist in the accomplishment of several objectives. First, it was desired that the March 1977 estimate, filed in summary form at that time, be presented in sufficient detail to identify two aspects of the estimate: quantities and prices of inputs to construct the pipeline, and the physical work to be accomplished by those inputs. The quantities of labor (man-hours of welding, for example) and material (example, miles of pipe) were to be shown separately from the unit prices used to compute the aggregate cost estimates which were filed. The identification within the March 1977 estimate of the physical work to be accomplished was to be achieved by requiring development and utilization of a "Work Breakdown Structure" (WBS). 93/ The March 1977 estimate was to be recast into WBS elements, such as Construction Spreads, River Crossings, etc., in order to facilitate comparison with the CCSE by observing the changes in resource inputs required to accomplish a given job.

Second, the quantities of resource inputs in the March 1977 estimate were to be displayed and multiplied by base-year prices. The "repriced" March 1977 estimate would then be ready for comparison with the CCSE. With "price" changes eliminated by the repricing procedure, differences in the estimates could be

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92/ The IROR mechanism as developed by the Commission attempts to eliminate the effects of general inflation in the assessment of cost and schedule control performance, which is the central feature of that mechanism. The attempt is made by selection of a base year at the time of filing the CCSE, and deflating actual capital expenditures to that base year before comparing actual costs with projected costs to determine cost and schedule control performance. The Commission's inflation adjustment mechanism is described at pages 111-119 of Order No. 31.

93/ *See* pages 25-38 of the attachment to the Alaskan Delegate's report for a discussion of the WBS's derivation and usage, and for a recommended WBS for ANGTS sponsors.

attributed either (a) to changes in the amounts of resources required to accomplish the original design which was the basis of the March 1977 estimate, or (b) to changes in the amounts of resources required because of a design change. The CCSE was to be similarly displayed. The WBS format was to be followed, with estimates to be presented at a sufficiently detailed level to fully describe the work to be accomplished. By requiring the CCSE to be supported by specific quantities and prices of resource inputs, the sponsors' filings would facilitate a comparison with the "repriced" March 1977 estimate, and, furthermore, those filings would provide a foundation for review of design changes and scope changes proposed to the Federal Inspector subsequent to the issuance of the final certificate. 94/

By order of September 6, 1979, 95/ the Commission directed that the sponsors of the prebuild portions of the ANGTS file their cost estimates by October 15, 1979 in accordance with the requirements set out in the Alaskan Delegate's Report. In order to assure expedition, the Commission ordered that review of the cost estimate formats and the CCSE's proceed concurrently in the ongoing adjudicatory proceeding in this docket. 96/

94/ The Commission's IROR mechanism provides for, at the discretion of the Federal Inspector, design changes between (a) the time of final certification of the project by the Commission and (b) the time of Federal Inspector approval of the projects's final design immediately prior to the commencement of construction. The IROR mechanism also provides for certain scope changes, also at the Federal Inspector's discretion. See, Order No. 31 at 120-138, and Order No. 31-B at 31-42.

95/ "Order on Procedures for Cost Estimates," Docket Nos. CP78-123, et al. (September 6, 1979).

96/ The Commission notes that the comparison between the March 1977 estimate and the CCSE is a requirement of the President's Decision, not of the Natural Gas Act (NGA); thus, the procedural requirements of the NGA do not apply. Similarly, Commission approval of the CCSE is primarily to establish a target for assessment of cost and schedule control performance under the IROR mechanism, and thus could be considered a ratemaking

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Northern Border requested an extention for filing the requisite cost estimate materials, which request was granted. Northern Border's filings were received on November 15 and 22, 1979.

Staff filed a motion on November 29 to reject the Northern Border cost estimate filings. The primary argument was that the Northern Border filing did not provide a basis for comparison of the March 1977 estimate with the CCSE. Specifically, staff alleged that:

> "Northern Border did not recast the March 1977 estimate into the formats of the certification cost estimate, but instead, started with the certification cost estimate and recast it into a two year construction program instead of a one year construction program." (Staff Motion at 5.)

Staff also noted that Northern Border did not provide the documentation of the CCSE's as required by the Commission's cost format criteria.

A technical conference was held on December 17, 1979 at Northern Border's offices in Omaha, Nebraska, at which time work papers supporting the development of the CCSE were made available to the trial staff. No progress was made, however, on resolving the dispute over the appropriate comparison with

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96/ (footnote continued from previous page)

matter, which could be determined through rulemaking procedures pursuant to Section 403(c) of the Department of Energy Organization Act.

The Commission utilized the adjudicatory proceeding in this docket for addressing cost estimate issues for the prebuild projects because it was the most expeditious procedure under the circumstances presented. We note, however, that such procedures may not be the most expeditious for consideration of the cost estimates for the Alaska segment, and that the Commission may develop special procedures for consideration of those estimates.

the March 1977 estimate. Subsequently, on January 4, 1980, 97/ the Commission directed Northern Border to prepare a new March 1977 "repriced" estimate using certain specified assumptions to derive the estimate where no known design changes were involved. Northern Border filed the revised March 1977 estimate as required on January 14, 1980.

On February 1, 1980, the trial staff filed answering testimony. In its initial brief at the close of the adjudicatory proceeding, the staff filed a final version of its proposed CCSE and the Center Point value which resulted from its comparison with the March 1977 estimate. Northern Border's initial brief also discussed cost estimate issues, as did both parties' reply briefs. No other briefs addressed the cost estimate issues. The final cost estimates filed by Northern Border and the trial staff are summarized on Table A on page 105 of this order. The cost estimates for the prebuild portion as filed are (in thousands):

a. March 1977 Estimate in 1975 Dollars:

1.	Northern Border	$743,558
2.	Staff	705,177

b. March 1977 Estimate-Repriced in 1979 Dollars:

1.	Northern Border	$1,226,583
2.	Northern Border-Filing per January 4 Order	1,139,604
3.	Staff	956,230

c. Certification Estimate (CCSE) - 1979 Dollars:

1.	Northern Border	$1,094,191
2.	Staff	997,350

No agreement on any of these estimates was reached between Northern Border and staff, nor was there agreement on the proper methodology for repricing the March 1977 estimate. However, an agreement was reached by stipulation on two items:

97/ "Order Requiring Refiling of Certain Materials by Northern Border, and Clarifying Prior Commission Orders," Docket No. CP78-123, et al., (January 4, 1980).

1. Costs in the CCSE may be adjusted for a proposed rerouting of the pipeline around the coal fields in North Dakota; and

2. The proper methodology for computing the Center Point is to have the March 1977 estimate reflect a two-year construction schedule and the CCSE a one-year construction schedule.

V.B. Methodological Issues

Two principal methodological issues were raised. One concerns the appropriate construction schedules to be reflected in cost estimates for purposes of computing the Center Point. The other concerns the method for repricing the March 1977 estimate into base year dollars.

V.B.1. Methodology for Preparation of Cost Estimates

The March 1977 cost estimate for the complete Northern Border project was based on a two-year construction schedule. The CCSE for the Northern Border pre-build project, presented in Exhibit NB-13, was based on a one-year construction schedule. Northern Border, in repricing the March 1977 estimate into base year dollars, continued to use a two-year construction schedule (Exhibit NB-12). The Commission's January 4, 1980 order noted the differences in construction schedules. Northern Border responded by filing Exhibit NB-12A on January 14, 1980. However, Northern Border objected to the use of the revised exhibit in the determination of Northern Border's Center Point. 98/

Northern Border's objection noted, first, that in 1977 it would have adopted a two-year schedule for the prebuild if it had been considered then (and not a one-year schedule). Second, the one-year schedule for the CCSE was forced upon them in order to meet a November 1, 1981 in-service date. 99/

98/ Joint Testimony of J. C. Pyle and L. E. Reynolds, tr. 536-541.

99/ Tr. 538.

Northern Border prefers a two-year schedule for the CCSE. This low-risk schedule would result in a November 1, 1982 in-service date. 100/ Northern Border's objection noted that their major benefit to be derived from the use of a two-year schedule in the repriced March 1977 estimate was the higher Center Point, and argued that the alternate comparison would be unfair:

> "We believe we have acted responsibly in the public interest in undertaking a one year program to try to save this project, and we do not feel that it would be fair or equitable to increase the already high risks we have assumed by what we believe would be an arbitrary and artificial reduction of the center point value." (Tr. 540.)

Staff concurred with Northern Border's position and entered into the following stipulation:

> "Northern Border Pipeline Company (Northern Border) agrees that in this proceeding the above described proposed evidence, if admitted, will be used by Northern Border in the pre-build proceeding only in support of the position that any NB-12 estimate (the March 1977 cost estimate repriced in 1979 dollars) used for the purpose of calculation in the IROR mechanism specified in Orders 31 and 31-B of RM78-12 should be based on a two year construction schedule." (Tr. 586.)

The purpose of the Commission's methodological instruction and order to re-file the March 1977 repriced estimate was to provide a comparison between the CCSE and the March 1977 estimate based on an assumption about construction schedule that was consistently applied to both estimates. The Commission agrees, however, that the one-year construction schedule involves more risk to Northern Border's equity sponsors than would be encountered with a two-year construction schedule. Accordingly, if, as specified in its January 4 order, the Commission were to utilize its methodology to determine Northern Border's Center Point, the Commission would feel obliged to revise Northern Border's IROR Risk Premium.

100/ Testimony of C. D. Schulz, tr. 574.

The Commission observes that the same risk compensation effect is achieved by utilizing the methodology for determining the Center Point which was agreed to by the staff and Northern Border. Instead of adjusting the IROR schedule with an additional IROR Risk Premium, their methodology achieves a similar result by effectively adjusting the Center Point. Utilizing their methodology and Northern Border's estimates of direct capital costs after certain adjustments by the Commission (see discussion, infra), the Commission computes an expected rate of return of 15.5305 percent if Northern Border's actual cost and schedule control performance is exactly as estimated in the CCSE, that is, the Cost Performance Ratio equals 1.0. This value represents a premium 101/ of .6212 percentage points over the expected return of 14.9093 percent at the same value of the Cost Performance Ratio utilizing the Commission's methodology. An increase of that amount in Northern Border's IROR Risk Premium is within the range contemplated by the Commission. The Commission thus accepts the Center Point determination methodology stipulated by Northern Border and the staff.

V.B.2. Methodology for Repricing the March 1977 Cost Estimate

Northern Border's filing of its March 1977 cost estimate in 1975 dollars (Exhibit NB-11) was a best effort to derive a "pre-build" estimate from an estimate for the total segment--an estimate with considerable documentation missing. Northern Border did not use this estimate to derive Exhibit NB-12, but instead utilized a variety of sources 102/ including the CCSE. Staff objected to the revised pricing, arguing that Northern Border did not recast the March 1977 estimate into the formats of the CCSE, but, rather, started with the CCSE and recast it into a two-year construction program and submitted that as their March 1977 repriced estimate.

The Commission, in its order of January 4, 1980 (at 4), recognized the difficulty of deriving the 1977 estimate:

101/ Northern Border estimated the difference due to the change in construction schedules to be $85,642,000. This is the difference between the initial estimates filed for NB-12 and NB-12A. The 14.9093 percent is thus based upon a repriced March 1977 estimate of $1,038,206,000 less $85,642,000 or $8,952,564,000.

102/ The sources were essentially those identified in the January 4, 1980 order as sources for the refiling estimate.

"The Commission recognizes that a March 1977 cost estimate for Northern Border's prebuild portion of the Alaska Natural Gas Transportation System does not exist, per se, and that analytical techniques must be used to derive such a value."

The Commission directed Northern Border to prepare a new March 1977 repriced estimate utilizing 1979 prices 103/ but utilizing quantities from three sources:

(1) May 1976 estimates for line pipe, line pipe installation and the communication system,

(2) "Later" 1976 estimates for other material used in the pipeline, and

(3) The 1979 CCSE for remaining cost elements.

That order also directed Northern Border to assume a one-year construction schedule, as discussed herein.

Staff continued to object to Northern Border's methodology as reflected in Exhibits NB-12 and NB-12A, and developed its own estimate for March 1977 repriced, utilizing escalation indices for most cost categories. The staff's methodology was explained as follows:

"For government agency costs, we used the same percentage used by Northern Border in NB-11. For the 42" line pipe, since sufficient detail on its quantities was available in NB-11, we used the prescribed Commission methodology. That is, we kept the 1977 quantities and substituted 1979 prices.

"There was insufficient detail to use this methodology for the remaining cost categories. For these remaining costs, we took the lowest subcategory of cost for material and labor provided by NB-11 and escalated it via a weighted composite inflation index (wci index). The only exception to taking the lowest subcategory of cost was for pipeline installation. For that category, we used the bottom line price provided by NB-11 of $130,205 thousand. (This excluded the $3,224

103/ 1979 is the base year for the CCSE.

> thousand for labor contigency.) The escalation of cost to 1979 dollars is shown in Exhibit ________ (DKH-3)." 104/

Trial staff used a two-year construction period in its calculations.

The Commission is thus offered a choice of two alternative methods to express the March 1977 estimate in base year prices. One, utilized by Northern Border, builds upon specific information from the several sources discussed above, each believed to be relevant to the 1977 design and specifications. This methodology is used in both NB-12 and NB-12A. The method utilized by staff is a hybrid; it applies a price index ("wci index") to portions of the March 1977 estimate as stated in 1975 dollars and applies 1979 prices for line pipe to 1975 quantities.

The Commission observes that the March 1977 estimate (in 1975 prices) which Northern Border derived and submitted has been recognized by all parties as lacking in detail and documentation. The Commission directed Northern Border to develop a March 1977 repriced estimate in a specific fashion because of these uncertainties. The staff, on the other hand, took those same estimates, the derivation of which could not be verified for purposes of dividing those estimates into quantities and prices, and used them as a base for escalation. The difficulties of using this "soft" base are illustrated in the estimate for "other material"; staff acknowledges that Northern Border's cost estimate for "other material" was derived by Northern Border "backing into it" by subtracting "pipeline material" from a "total cost" figure. 105/

The Commission does not find fault with the concept of applying appropriate price indices to a valid 1977 cost estimate baseline as a means of deriving a March 1977 repriced estimate. However, in the instance at hand, the Commission believes that the March 1977 estimate in 1975 dollars which was filed by

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104/ Donald K. Hart and W. R. Stancil, Joint Answering Testimony, tr. 949.

105/ Staff acknowledged that Northern Border's estimate for other material was the more valid estimate. See staff's initial brief at 65.

Northern Border is simply too "soft" to be considered for applying escalation indices. Further, the staff did not use a consistent methodology; that is, it did not apply escalation indices to all cost categories. The Commission is unable to determine the net effect of "mixing" the methodologies. Faced with a unique situation where a valid, "hard" estimate in 1975 dollars does not exist, and seeking to select a March 1977 repriced estimate with the best possible quantification of quantities and prices, the Commission chooses the Northern Border methodology and the accompanying estimate with appropriate adjustments, as filed in Exhibit NB-12.

Staff, in defending its use of wci indices, expressed concern about Northern Border's 1979 unit prices for installation. Staff testimony noted:

> "Look in the context of pipeline installation: If we substitute the quantities Northern Border implies should be substituted into NB-11 from NB-12 we find some cost increases in unit costs which cannot possibly be explained by productivity loss or by inflation. For instance, basic installations increases 300 percent, pig launcher installation increases 700 percent, receiver installation increases 600 percent, revegetation increases 600 percent; and on and on." (Tr. 798-799.)

The Commission recognizes this concern and addresses it and other cost estimation issues below.

V.C. Issues In Determining The Proper Value Of The Repriced March 1977 Estimate

Staff raised a number of issues with regard to Northern Border's repricing of the March 1977 estimate. Staff raised issues by cost category but did not summarize them because of their recommended rejection of the Northern Border methodology and estimate as contained in Northern Border's Exhibit NB-12. The various issues will be discussed below by cost category and a final value determined. Adjustments accepted by the Commission are summarized on Table B, at page 106 of this order.

V.C.1. The Problem of the Definition of a "1979 Price"

In deciding to accept or not accept adjustments recommended by the staff, the Commission has been called upon to make a number of difficult judgmental decisions. These decisions, discussed in more detail with each issue, focus upon a problem which was only fully appreciated subsequent to the issuance of the Commission's cost format criteria, namely, what is a meaningful definition of the term "base year price"?

Condition 7 of Order No. 31 required that the March 1977 cost estimate be resubmitted in the same format as the CCSE and recalculated in the same base-year prices. 106/ This instruction was expanded in the attachment to the Alaskan Delegate's Report 107/ to require that cost submissions depict separately the quantities and prices underlying the estimates. Specifically, the exhibit to be filed for the March 1977 estimate was to separately identify the quantities of the various resource inputs required for the pipeline, and the prices of those inputs. 108/ The exhibit containing the repriced March 1977 estimate would then simply substitute base year (1979) prices for the original ones, but maintain the same quantities of resource inputs. Finally, for the CCSE, base-year quantities and prices were to be shown.

As noted earlier, Northern Border's March 1977 estimate was incomplete in its documentation of 1975 quantities and 1975 prices. This presents two types of problems in trying to reprice that estimate: one problem involves the use of bid prices; the other problem is with the definition of a 1975 quantity.

The first problem, use of bid prices for Installation Labor, was argued by staff to allow inclusion of significant amounts of "cost growth" in the March 1977 repriced estimate. 109/ This

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106/ Order No. 31 at 243.

107/ Delegate's Report, *supra*, at 39-45 of attachment.

108/ The March 1977 cost estimates had actually been prepared in late 1975/early 1976, and thus were expressed in constant 1975 dollars.

109/ "Cost growth" refers to a requirement for additional units of resource inputs required to accomplish a given job, and is to be distinguished from "cost escalation," which we use in discussing the impact of inflation on the unit cost of any given resource input, either labor or material.

significant cost growth has been masked by the use of bid prices, rather than man hour quantities multiplied by hourly rates. To use a hypothetical example, suppose that Northern Border had estimated in 1977 that it took 10,000 hours to do a given job. At, say, $15 an hour, this would result in a cost estimate of $150,000. If the cost in 1979 is $25 an hour, then the Commission expected to see 10,000 hours at $25 an hour (or $250,000) in the repricing. But suppose that in 1979 Northern Border shifted to a bid pricing technique. Suppose further that reduced labor productivity meant that 14,000 hours would be needed to do the job. The total bid might be 14,000 hours at $25 an hour (or $350,000); of this, 4,000 hours at $25 an hour (or $100,000) is "cost growth." Now, if only lump sum dollar bids (without man-hours back-up) are available, this growth is masked.

Northern Border argues that the bid price to install the pipe in a given construction spread is a "1979 price," albeit one which happens to be the product of 1979 wages and, perhaps, greatly increased estimates for man-hours. This issue of whether a bid price is a "1979 price," or is a representation of man-hours times 1979 labor rates, is the principal issue in deciding whether some adjustment to Northern Border's CCSE is warranted under "Pipeline Installation."

The second problem, namely, the definition of a "1975 quantity," involves cost categories reflecting a "bundle" of resources represented by a total dollar estimate. Cost categories presenting this problem include Ad Valorem Taxes and Project Management. In disaggregating costs in the March 1977 estimate for re-pricing and comparing with the CCSE, Ad Valorem Taxes, for example, could be considered as a bundle consisting of:

1) Taxes of this type enacted prior to preparation of the March 1977 estimate, multiplied by the amount of those taxes in the year in which that estimate was prepared (1975), and

2) Such taxes enacted after preparation of that estimate, multiplied by a price for those taxes of zero.

Alternatively, the ad valorem taxes enacted after preparation of the March 1977 estimate could be considered cost growth, similar to the additional man-hours required in the productivity example given above. Under the rules articulated by the

Commission for the IROR mechanism in Orders No. 31 and No. 31-B, the new taxes would be considered price escalation in the first alternative, and would be acceptable for repricing the March 1977 estimate. However, if the new taxes were considered cost growth, as in the second alternative, they could not be included in the repricing March 1977 estimate. As the IROR rules use the repriced March 1977 estimate for comparison with the CCSE to determine the Center Point of the IROR schedule, the two alternative treatments of taxes enacted since 1975 would result in slightly different IROR schedules.

V.C.2. Pipeline System - Material (Line Pipe)

Staff discovered that in repricing its March 1977 estimate, Northern Border used the proper quantities of line pipe, but used the price of a better grade of pipe than had been used in the March 1977 estimate. A TI-1 pipe was costed in 1977 whereas a TI-2 pipe was costed in 1979. Staff noted that the TI-2 pipe costed out at $513,697,000 in base year (1979) dollars, some $24,113,000 more than the 1979 cost of TI-1 pipe. Northern Border acknowledged that the TI-1 pipe could not be used in actual construction, although it had been used in their March 1977 cost estimate. 110/

The Commission accepts the staff's proposed reduction of $24,113,000 in the repriced March 1977 estimate. The Commission

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110/ In its initial brief (at 23-24), Northern Border states:

> "The price quotation Staff used was for U.S. Steel TI-1, 42", X-65 pipe. The TI-1 designation refers to toughness factor, and means no toughness index factor, thus employing a pipe specification that Northern Border could not use. Northern Border's specifications for line pipe, on which its bid prices for both NB-12 and NB-13 were based, requires substantial toughness index factor, and would not use pipe failing to meet that specification. Quite obviously, the pipe quantities that are to be priced in 1979 dollars must be quantities of usable pipe. The adjustment is mandatory." (Footnote omitted)

believes the pipe quality question is an example of the type of understatement of costs in the March 1977 estimate for which the President included an adjustment to that estimate. See note 86 above. To fail to reduce the repriced March 1977 estimate for this factor would result in compensating for it twice, because of the workings of the formula for determination of the Center Point specified in Order No. 31. The Commission wishes to avoid such double compensation.

V.C.3. Pipeline System - Material (Ad Valorem Taxes)

Staff objected to Northern Border's inclusion of $26,664,000 of ad valorem taxes and $2,421,000 of excise taxes imposed on materials, supplies and equipment brought into local taxing districts because these taxes were not included in the March 1977 estimate. Northern Border acknowledged that these $29,085,000 were new taxes imposed since 1975 but argued for their inclusion in any repricing.

As noted earlier, the Commission views this as an example of a difficult methodological issue. If one views new taxes as a "change in quantity," then the taxes should be excluded from any repricing. However, if one views the line item "taxes" as simply a change in price, then substitution of base year amounts of such taxes seems appropriate. Though perhaps difficult methodologically, it seems unreasonable to argue in effect that Northern Border should have anticipated imposition of new taxes that did not exist when their March 1977 estimate was prepared. We see a distinction between this issue and that of the quality of the line pipe, for example, because the pipe quality standard could and should have been correctly ascertained in 1977. Therefore, no adjustment for taxes is made to the NB-12 estimate.

V.C.4. Pipeline System, River Crossings and Compressor Station Installation

Staff observed that Installation Labor unit prices for various functions increased over a range from 62 percent to 594 percent from 1975 to 1979, a factor too great to be attributable solely to "inflation." 111/ Staff argues that the base year prices proposed to reprice the March 1977 estimate include significant cost growth, hidden because installation was not broken down in sufficient detail. Staff asserts that included in the (base year) prices are a change in the quantity of labor input due to lower estimates for labor productivity. Staff noted that:

> "Witness Reynolds testified that losses in labor productivity between 1975 and 1979 results in a 43.3 percent increase in labor costs which increase is separate from the price inflation for labor." (Staff Initial Brief at 79.)

111/ Staff's chart in its initial brief (at 66-69) shows:

Cost Differential Shown in NB-33

		NB-11 Unit Price	NB-12 Unit Price	Increase
1.	42" pipe	21.22	34.48	62 %
2.	Unload/Stockpile 42" pipe	.52	1.67	221
3.	Double Joint Mainline pipe	94.07	277.84	195
4.				
5.	Furnish & Install Set-on Wts.	240.19	501.00	108.5
6.	Rock Excavation	10.12	29.90	195.45
7.	Padding Ditch	3.58	5.95	66
8.	Sack Breakers	1.94	3.01	55
9.	Fab & Install Sta. Valve	78,385.	249,000.	218
10.	Fab & Install Single Valve	38,205.	49,700.	30
11.	Fab & Install Launcher	18,000.	125,000.	594
12.	Fab & Install Receiver	18,000.	106,000.	489
14.	Reclamation & Revegetation	62.16	382.00	514
15.	Camps	9,221.	38,127.	313

Staff concluded that Northern Border's repriced installation estimates must be rejected (and staff estimates utilized).

Northern Border defended inclusion of productivity losses as a matter of practicality, suggesting that a quote from a supplier effectively defines a "1979 price." Northern Border argued:

> "It defies logic and reason to reflect one form of inflation or 'cost growth' (dollar inflation) in moving from an earlier to a later time period, and refuse to reflect another (in this case more significant) form of inflation or 'cost growth' (productivity losses). If adjustments for inflationary effects are to be permitted at all, then all identifiable and determinable forms of such 'cost growth' must be included. In addition, there is no practicable way to avoid reflecting productivity losses for the most important direct cost category: material prices. Productivity losses occurring over time are contained within the price, from time to time, of the material costs for the prebuild project. Equally important, there is no difference in the basis for estimates of materials and installation costs. Each is determined by quotes from suppliers. Northern Border used quotes from suppliers for pipe, compressors, and other equipment; it used quotes from contractors for installation of that material. It cannot seriously be questioned that the cost differential between 1975 dollar pipe quotes (or compressor quotes, etc.) and 1979 dollar pipe quotes does reflect the mills productivity experience between those dates. If Staff is to be consistent in its 'cost growth' position, it should demand detail quantities of tasks, man-hours, etc. from the pipe mills as of 1975, and project those forward to 1979 without adjustment for productivity losses. Of course, if such a task was undertaken, Staff should start with the iron ore, its conversion to steel, manufacture into plate and rolling into pipe, and produce a truly detailed quantity estimate excluding productivity effects throughout the chain, the result of which would be that no one could ever build a pipeline under an IROR mechanism--or, we might add, an LNG plant, coal gasification plant, synthetic plant, or any other structure imaginable.

> Staff, of course, has not done that and does not propose to do so, for the obvious reason that such a procedure would be absurd. Yet Staff clings to the notion that such a 'head in the sand' approach is appropriate for but one cost category. Staff simply accepts the 'cost growth' attributable to productivity experience which is an integral part of the quoted material prices." (Northern Border Reply Brief at 16.)

The Commission observes that Northern Border did not prepare the re-priced March 1977 estimate of installation costs by taking the estimates for man-hours, equipment rental hours, etc. from their working papers supporting the March 1977 estimate and pricing them using 1979 prices for the same inputs. Rather, installation tasks were aggregated to the level for which bids had been sought for the CCSE; then the contractor's bid for that task was used to prepare the repriced March 1977 estimate. That contractor's bid included all factors considered by him, including decreased labor productivity.

The Commission agrees that it is not feasible to go into bids from steel mills, etc., to analyze their productivity changes; however, it certainly is possible to analyze the labor hours in a construction bid. In fact, the Commission believes that standard pipeline industry practice is for sponsors to make their own estimates of labor hours by function for use in checking the validity of bids. Had Northern Border chosen to submit their estimates using the man-hours on which the March 1977 estimate had been based and 1979 wage rates, then the changes would have been obvious. The Commission believes that installation labor productivity was another of the areas that, prior to the adjustment made in the President's Decision, were simply too low in the March 1977 estimate, and that the adjustment was meant to include this cost growth. To fail to adjust the repriced version of that estimate on this point would be to reward the project sponsors for having underestimated Northern Border's cost at that time. The Commission believes, therefore, that an adjustment to Northern Border's repriced March 1977 estimate for lowered labor productivity is in order.

a. Pipeline Adjustment

The appropriate amount of adjustment is a difficult matter. Northern Border's testimony cited by the staff that there has been a 43.3 percent increase in labor costs due to losses in labor productivity may be used as a guideline. Exhibit NB-11 shows pipeline installation as $133,429,000 in 1975 dollars; NB-12 detail shows $264,401,000 for that category in 1979 dollars for a total increase of $130,972,000. The Commission assumes that 43.3 percent of that increase is for lowered labor productivity 112/ and 56.7 percent is for other reasons (inflation, market conditions, etc.). Thus 43.3 percent of the cost increase of $130,972,000 is $56,711,000. Accordingly, the Commission will reduce the pipeline installation costs in Northern Border's repriced March 1977 estimate by $56,711,000.

b. River Crossings, Compressor Stations, and Meter Stations Adjustments

Staff developed a case concerning installation costs for these cost categories similar to that for pipeline installation. The Commission will reduce the cost increase in the installation costs by the 43.3 percent lower labor productivity identified by Northern Border, computed as follows (in thousands):

	NB-11 $1975	NB-12 $1979	Cost Increase	43.3%
River Crossings	2,179	15,165	12,986	5,629
Compressor Stations	970	2,114	1,144	495
Meter Stations	765	608	decrease	0

V.C.5. Land, Right of Way, Permits

Approximately 60 miles of the originally proposed Northern Border route in Dunn, Mercer, Oliver, and Morton Counties, North Dakota, would cross lands identified as having potential for commercial coal development using surface mining. Several major coal fields have been identified there: the Dodge-Halliday field in Dunn County, the South Beulah field in Mercer and

112/ Northern Border used the 43.3 percent figure for lower productivity in recommending an upward adjustment to the staff's version of the repriced March 1977 estimate. See Northern Border's initial brief, Appendix B.

Oliver Counties, and the New Salem Field in Morton County. Emplacement of the pipeline would preclude mining operations, requiring Northern Border to purchase the mineral rights within the pipeline's right-of-way. Northern Border assessed the probable cost of the mineral rights to be $41,323,000 in 1979 dollars and included this amount in the March 1977 repriced estimate for this category of costs.

Staff recommends the deletion of the $41,323,000 from the total right-of-way cost estimate of $64,801,000. Staff argues that Northern Border did not include any value for coal rights when the March 1977 estimate was prepared, and, thus, to include the 1979 value would be to mask cost growth. Staff argues that the only proper place to reflect the new value is in the CCSE. Elimination of the value of the coal from the March 1977 repriced estimate will then highlight the cost growth involved.

Northern Border admits that the coal rights were not given a value in the 1975 estimating process, although their existence was recognized, but argues that right-of-way has simply been "repriced" in 1979 dollars and the repricing includes the cost of purchasing mineral rights. 113/

The Commission views this as one of the difficult decision areas referred to earlier under the discussion of the meaning of a "1979 price." Staff, in effect, views the *quantity* of 1975 mineral rights in Northern Border's costs for right-of-way as being zero, with the price also being zero. The recognition of the higher value in 1979 is thereby attributable to cost growth. Alternatively, Northern Border construes the coal fields' "quantity" to be a positive value (*i.e.*, one). Given an unchanged 1975 quantity, the replacement of a 1975 price of "zero" with a 1979 price of $41,323,000 is appropriate, according to Northern Border.

Given Northern Border's recognition in 1975 of the existence of the coal fields, the Commission concludes that Northern Border's repricing is not a proper revaluation of an existing quantity, because Northern Border could and should have included

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113/ Tr. 556-557.

a cost for the value of the coal in its March 1977 estimate. Therefore, an adjustment will be made to the cost estimate for right-of-way, by deleting those costs in the repriced March 1977 estimate.

V.C.6. Communication System, Operation and Maintenance Equipment, Survey and Mapping

Staff notes that problems exist in supporting the March 1977 estimates for these categories in detail, and raises the labor productivity issue discussed above under Installation Labor. Because of the relatively small amounts of labor involved in these categories, and the uncertainties associated with quantifying the labor productivity adjustment, the Commission accepts the Northern Border estimate. Therefore, no adjustments will be made to these categories.

V.C.7. Project Management and Government Agency Costs

Northern Border acknowledges that the March 1977 estimate for this category is conceptual in nature, and without detailed support:

> "I think we have testified somewhere that the project management for the March 1977 estimate was a conceptual type estimate as far as we have been able to determine. We have not been able to find any detailed computations for the project management part of the 1977 estimate." (Tr. 661.)

Northern Border repriced its March 1977 estimate for both Project Management and Government Agency Costs by using the values in the CCSE. Northern Border's work papers in support of their CCSE (Exhibit NB-13; tr. 583) segregate Project Management costs into three categories (in thousands):

Government mandate	\$ 7,260
Non-traditional	10,937
Sub-Total	\$ 18,197
Traditional	38,707
Total in NB-J	\$ 56,904

The first category reflects the additional costs attributable to the terms of the President's Decision. The second category reflects other governmental costs not traditional to a typical pipeline project. The third category consists of the costs of traditional engineering, design and project management functions.

The CCSE reflects a one-year construction schedule, whereas the March 1977 repriced estimate reflects a two-year construction schedule. The additional costs of the longer schedule increase the project management costs from $56,904,000 to $59,890,000.

Staff recommends the exclusion of $32,000,000 of the $59,890,000 estimate, attributable to additional Project Management and Government Agency Costs mandated for this project by the government but omitted from the original estimate. Staff argues that these government-mandated and non-traditional costs were not conceived of by the estimators in 1975 and no valuation was given to these costs. Therefore, recognition of these costs should take place only in the CCSE. Otherwise, cost growth since 1975 will be masked. 114/

Northern Border acknowledges that the costs at issue are all imposed by new governmental requirements (since 1975), but argues that such costs were intended to be included in the repriced March 1977 estimate by the terms of Order No. 31. 115/

114/ Staff's initial brief at 62.

115/ Northern Border stated in its reply brief (at 23-24) that:

> "It is hardly conceivable that the government itself would first impose new and additional costs previously unknown on the applicants, and then deny them the right to include such costs in a repricing of the original estimate. It clearly was not contemplated that this be done by Order 31, which affirmatively recognizes that these costs were not included, and could not have been included in the 1977 estimates,

(footnote continued on next page)

Northern Border cites as further evidence the Commission language in its order of January 4, 1980 directing inclusion (in its repricing of the March 1977 estimate) of the same costs as are in its CCSE.

Staff, in effect, argues that there are several components to the Project Management cost category, of which only the "traditional costs" were included in the March 1977 estimate. The other costs were not included at all and, hence, had both a quantity of zero and a price of zero. Northern Border does not disagree with the concept of a "zero quantity," but argues for the allowance in a repricing because, otherwise, the Commission's Center Point formula as developed in Order No. 31 was set too low. That is, the Center Point should include a factor greater than 1.1 if these costs must be absorbed therein.

The Commission is not persuaded by Northern Border's Center Point argument and concludes that cost growth of this nature was intended to be covered by the adjustments to the March 1977 estimate which were made in the President's Decision, which, in turn, were the genesis for the formula which was developed in Order No. 31 for determining Northern Border's Center Point. (A more extensive discussion of cost growth and the Center Point follows under the heading of "Contingencies.") The Commission supports the position that the 1975 quantities for non-traditional

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115/ (footnote continued from previous page)

nor were they included in the determination of the 1.1 Center Point Formula Constant provided for Northern Border by Order 31. At page 44 of Order 31, the Commission recites that the President's Decision factored in cost-growth estimates of approximately 10% for Northern Border in the evaluations leading to approval of the project. These evaluations of the 10% over-run are precisely defined in Order 31 at page 12 as "an estimate of cost over-runs under expected conditions." (Emphasis supplied). The President's Decision and Report itself at page 149 carries the headnote "Cost Over-run Estimates Under Expected Conditions." The term "expected conditions" can refer only to those conditions expected by the project estimators and by the evaluators for President at the time the estimates were prepared and evaluated. The additional costs attributable to governmental mandates were required thereafter by the terms of the President's Decision."

costs were zero, obviating any effort at repricing them. Accordingly, an adjustment to Northern Border's repriced March 1977 estimate is deemed appropriate.

The derivation of the staff estimate of $32,000,000 for non-traditional costs is not clear in the record. Therefore, the Commission accepts an adjustment to Project Management Costs of $18,197,000--the Northern Border estimate for non-traditional costs. The $18,197,000 is 30.38 percent of the $59,890,000 total for Project Management. In the absence of an alternative method to derive an adjustment for Government Agency Costs (GAC), the Commission will apply the 30.38 percent factor to the GAC total of $9,996,000. The Commission's adjustment for this category is, thus, $3,036,000.

V.C.8. Commitment Fee for Debt

Staff recommends the exclusion of the entire estimate of $17,634,000 as being inapplicable. Staff did not provide text to support the deletion on their Exhibit S-44, but we infer that their reasoning is that Condition 4 of Order No. 31 defines "Projected Capital Costs" as the sum of direct construction costs in the CCSE and a Finance Charge calculated from the "Real Rate of Return" (set in Condition 6 at 5 percent - see Order No. 31 at 242); therefore, any finance-related costs, such as the "Commitment Fee for Debt," should be excluded from the construction cost categories. Northern Border did not address this issue. The Commission agrees with the position that Order No. 31 excludes "Commitment Fee for Debt," and will delete the full amount of $17,634,000.

V.C.9. Contingencies

Northern Border included a general contingency factor of 6.1 percent of other direct costs in its original March 1977 estimate and in the March 1977 repriced estimate. Staff recommends the elimination of all Contingencies ($64,574,000) on the grounds that the intent of Order No. 31-B is to cover such costs in the determination of the Center Point. 116/

Northern Border, in its initial brief (at 11-14), argues for the full retention of Contingencies on the grounds that:

1. Pipeline estimates normally include a contingency allowance as did the March 1977 estimate, and this fact was known to the advisors who established the Center Point formula. Otherwise, they would have established a higher figure than the 1.1 constant.

2. Order No. 31-B does not exclude normal contingencies from estimates; only abnormal contingencies are excluded.

3. The Commission, by the wording of its order of January 4, 1980 requiring the repricing of Contingencies in the same manner as the certification estimate, endorses the inclusion of normal contingencies.

The Commission confirms Northern Border's opinion that an allowance for normal contingencies is acceptable for cost estimates submitted for use in Center Point determinations. The Commission's prior orders are consistent on this point. First, the Commission adopted the Alaskan Delegate's Report of August 3, 1978, which incorporated "Contingencies" in the

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116/ In its initial brief (at 95), staff states:

> "Staff places particular reliance on the Commission's explicit statement that contingency for unexpected events are not to be included in the certification cost estimate since they are already included in the value of the Center Point. To include amounts for contingency subverts the purpose underlying the IROR. Specifically, the contingency of 6.1% which Northern Border includes in NB-12 and 13 allows for this amount of cost growth in addition to the cost growth contemplated by the proper Center Point." (Footnote omitted.)

recommended Work Breakdown Structure. 117/ Second, the CCSE approved by the Commission for the prebuild segments of the Western Leg specifically included a 7 percent allowance for contingencies. 118/ Third, the Commission in its order of January 4, 1980 directed Northern Border to include an estimate for contingencies in its repriced March 1977 estimate computed in the same manner as was done for the CCSE.

The Commission has previously dealt with the relationship between normal contingencies and the Center Point of the IROR schedule in its orders defining the IROR mechanism. 119/ In those orders, the Commission has distinguished among Change in Scope events, abnormal events and the conventional approach to estimation. These references may be categorized into three sets of "events" as concerns the Center Point:

1) Abnormal or unlikely events of such importance and consequence that the Commission has designated them as "Change in Scope" events. 120/ The cost consequences of these events are to be excluded from the cost estimates submitted for use in determining the Center Point. The project sponsors will be permitted to increase the Projected Capital Costs, which serve as the target for assessing cost and schedule control performance, by the estimated costs of Change In Scope Events as approved by the Federal Inspector.

117/ Delegate's Report; *see* page 34 of the attachment to that report. The title of the account is labeled "Management Reserve" (to accomodate Department of Energy language used in Cost/Schedule Control System Reports) but Table 3 of the report shows a direct correlation to "Contingencies."

118/ The Commission accepted the CCSE which had been agreed to by the project sponsors and the staff. See Western Leg order at 29. The agreed estimates included an allowance for normal contingencies.

119/ *See*, especially, Order No. 31-B at 6-7.

120/ *See* Condition 10, Order No. 31-B at 73.

2) Normal or likely events of a routine nature but of an unknown (but not significant) cost impact, such as are normally included in pipeline construction cost estimates as contingency or management reserve at rates, for example, of 5-7 percent. The cost consequences of these "anticipated unknown" events are to be included as contingencies in estimates submitted for use in determining the Center Point.

3) Abnormal or unexpected events that could substantially increase costs but which are not included in the list of Change In Scope events. Examples of such events are 100 year storms, major fires and floods. The cost consequences of these "unanticipated unknown" events are to be excluded from the normal contingency allowance discussed above, but because these events are not Change In Scope events they are covered only by the Center Point mechanism itself.

In sum, the Commission does not accept the complete elimination of normal contingencies as recommended by the staff. However, Northern Border's Contingencies estimate of $64,574,000 is 6.1 percent of total costs of $1,058,570,000 other than Finance Charges and Commitment Fee For Debt. Therefore, any reductions in this cost base would require a corresponding reduction in Contingencies. As discussed above, the Commission has directed the following reductions (in thousands):

Direct Costs	$ 86,948
Project Management	18,197
Right of Way	41,323
Gov't. Agency Costs	3,036
	$ 149,504
Contingency Rate	6.1%
Contingencies Reduction	9,120

The Commission will reduce by $9,120,000 the Contingencies account in Northern Border's repriced March 1977 estimate.

V.C.10. Finance Charges

As noted in the preceding discussion, Order No. 31, Conditions 4 and 6, establish a 5 percent Finance Charge to be applied to the direct construction costs to establish projected capital costs for IROR purposes. A similar allowance is required for the repriced March 1977 estimate because of the formula provided by Order No. 31 to establish Northern Border's Center Point. Reduction in direct costs in the repriced March 1977 estimate would therefore require an appropriate reduction in the Finance Charge.

The $85,805,000 Finance Charge in Northern Border's repriced March 1977 estimate (Exhibit NB-12) is based upon a two-year construction schedule. As a convenient method of computing an adjustment, rather than attempting to time-phase all the adjustments, the Commission will use a ratio method. That is, the ratio equals:

$$\frac{\text{Finance Charge (2-year period)}}{\text{Total Costs in NB-12 Other Than Finance Charge and Commitment Fee For Debt}}$$

In 1979 Dollars:

$$\frac{85,805}{(1,226,583) - (17,634 + 85,805)}$$

$$\frac{85,805}{1,123,144} = 7.6397 = 7.64 \text{ percent}$$

The Commission's reduction of the Finance Charge is $12,119,000, computed as follows (in thousands):

$ 86,948	Direct Costs
18,197	Project Management
41,323	Right of Way
9,120	Contingencies
3,036	Government Agency Costs
$ 158,624	Total Reduction Subject to Financing
7.64%	Finance Rate Ratio (2-year Schedule)
$ 12,119	Finance Charge Adjustment

The Finance Charge adjustment completes the Commission's review of the repriced March 1977 estimate, with total adjustments made as follows:

Total Reductions Subject to Financing	$158,624,000
Finance Charge Adjustment	12,119,000
Commitment Fee for Debt Adjustment	17,634,000
Total Adjustments	$188,377,000

V.C.11. Determination of the Final Value of the Repriced March 1977 Estimate

As discussed above, the Commission has determined that adjustments to the Northern Border submission (Exhibit NB-12) totaling $188,377,000 are appropriate. The final value of the repriced March 1977 is therefore established at $1,038,206,000:

Northern Border Submission (NB-12)	$1,226,583,000
Adjustments	(188,377,000)
Commission's Final Value	$1,038,206,000

V.D. Issues In Determining The Proper Value Of The Certification Cost And Schedule Estimate

Staff raised four issues with regard to the Northern Border CCSE of $1,094,191,000 (Exhibit NB-13). Of these, one item pertaining to rerouting the pipeline around the coal fields in North Dakota was the subject of a stipulation. These matters will be discussed below and a final value determined.

V.D.1. Coal Rights

Staff recommended the elimination from the right-of-way cost category of the $41,323,000 value for coal rights, arguing that Northern Border had stated its commitment to reroute its pipeline around the coal fields. Coal rights of $41,323,000 were eliminated, but $11,443,000 was added back as an estimate of the cost of rerouting the pipeline, for a net reduction of $29,880,000. The rerouting alignment cost estimate was made by staff. Northern Border agreed to this reduction in its reply brief (at 2). The Commission accepts this design change. Accordingly, the CCSE for right-of-way is decreased by $41,323,000 and the pipeline material and installation category is increased by $11,443,000, for a net reduction of $29,880,000. 121/

121/ The Commission takes this opportunity to clarify one aspect of Order No. 31-B, regarding revisions to the Projected Capital Costs target for the IROR mechanism. At pages 41 and 42 of Order No. 31-B, the Commission expressed a willingness to accept Northern Border's proposal that Projected Capital Costs should not be reduced for design changes that reduce costs. It has occurred to us that, in theory at least, abuses could arise in the following two types of situations:

1) Project sponsors were aware of cost-saving design changes at the time of consideration of the CCSE, but postponed them until after CCSE approval in order to retain a high CCSE and thus improve their expected cost performance ratio, and consequently their IROR; or

(footnote continued on next page)

121/ (footnote continued from previous page)

2) Certain optional assumptions (of which the project sponsors had knowledge at the time of preparation of the CCSE), such as alternate (cheaper) sources or (lesser) specifications for materials or equipment, were omitted in preparing the CCSE for the purpose of increasing its value, only to be changed once the CCSE had been approved.

The Commission still believes that Northern Border's basic suggestion is valid. To eliminate any potential for abuse, the Commission states that neither of the two above described situations were intended to result in design changes without adjustment in Projected Capital Costs. Orders No. 31 and No. 31-B were premised on the following assumptions:

1) Project sponsors did not know about cost-saving design changes at the time of preparation of the CCSE if such design changes are to be approved without lowering Projected Capital Costs; and

2) If optional assumptions were made in preparation of the CCSE, cost-saving design changes will continue to utilize those same assumptions unless the assumption made was the correct one at the time of preparation of the CCSE but had since become inappropriate.

The Commission's intention in accepting Northern Border's suggestion was exactly the reason that led Northern Border to propose it, namely, to give the project sponsors an incentive to propose design changes that reduce costs. The Commission recognizes that implementing such an intention will be difficult, and will inevitably depend on the exercise of administrative judgment. The Commission intends that the Federal Inspector will be the one to exercise such judgment as he sees fit, and the Commission believes that it has structured the IROR mechanism in a manner which fully authorizes him to do so.

V.D.2. Omaha Office Overhead

Staff recommended the elimination of $131,000 from the Right-of-Way cost category by reducing the Omaha Office overhead from 135% to 50%. Further, staff eliminated $2,808,000 from the Project Management cost category for the same reason. Northern Border presented evidence in support of their contention that the overhead rates are reasonable. The Commission agrees with the reasonableness of Northern Border's overhead rates and makes no adjustment to either the Right-of-Way or Project Management cost categories for their overhead component.

V.D.3. Meter Station Construction Supervision

Staff recommended the elimination of $342,000 from the Project Management cost category on the grounds that a more reasonable approach was possible. Northern Border presented evidence in support of their position that their approach had been misunderstood and was, in fact, reasonable. The Commission considers this matter to be one of management judgment. Accordingly, the Commission accepts the Northern Border position and makes no adjustment to the CCSE for this item.

V.D.4. Contingencies

Staff recommended the elimination of the $61,023,000 of Contingencies. As discussed above, the Commission does not adopt that approach, and makes no general reduction in Contingencies. However, the reduction of $29,880,000 for rerouting around the coal field requires a 6.1 percent reduction in Northern Border's CCSE for Contingencies, or $1,823,000.

V.D.5. Finance Charges

Staff recommended a reduction in the Finance Charges estimate in an amount appropriate for its recommended reductions. Commission adjustments as discussed above total (in thousands):

Net reduction for rerouting	$29,880
Contingencies at 6.1%	1,823
Direct Costs Reduction	$31,703

Computation of the exact amount appropriate for reduction of Finance Charges would require monthly time-phasing of the direct cost reductions. In the absence of such information, the Commission will use a ratio methodology to compute the adjustment. The Finance Charge of $30,442,000 in Exhibit NB-13 is 2.86 percent of all other costs of $1,063,749,000. Therefore, the Commission's adjustment to the Finance Charge is 2.86 percent of $31,703,000 or $907,000.

V.D.6 Determination of the Final Value of the CCSE

The Commission required adjustments to the Northern Border CCSE submission contained in Exhibit NB-13 as follows (in thousands):

Relocating around coal fields	$ 29,880
Contingencies at 6.1%	1,823
	$31,703
Finance Charges at 2.86%	907
Total Reductions	$ 32,610
Submission Value	1,094,191
Final Value	$1,061,581

The final value of the CCSE is, therefore, established at $1,061,581,000 in October 1, 1979 dollars.

V.E. Comparison Of CCSE To Repriced March 1977 Estimate

The Commission has determined that the final values of the estimates shall be as follows (in thousands):

Certification Cost and Schedule Estimate	$1,061,581
Repriced March 1977 Estimate	$1,038,206

The CCSE is 102.3 percent of the repriced March 1977 estimate. The Commission finds, as noted above, that the CCSE does not materially and unreasonably exceed the March 1977 estimate.

V.F. Determination Of The Center Point

Northern Border has elected to use the formula established in Condition 12 of Order No. 31 (at 247) for establishing the Center Point for its IROR schedule:

$$\text{Center Point} = 1.1 \text{ times } \frac{\text{March 1977 Cost Estimate + Finance Charge}}{\text{Certification Cost Estimate + Finance Charge}}$$

The March 1977 estimate is to be expressed in base year (1979) prices for this computation.

The Commission has agreed to use a revised March 1977 estimate which is based upon a two-year construction schedule, as discussed in section B above, and a CCSE which is based upon a one-year construction schedule. Use of the final values for these estimates, as determined by the Commission in sections C and D above, yields a Center Point of 1.0758 computed as follows:

$$\frac{1.1 \times \$1{,}038{,}206{,}000}{\$1{,}061{,}581{,}000} = 1.0758$$

TABLE A

PRE-BUILD PORTION OF NORTHERN BORDER SEGMENT OF EASTERN LEG, ANGTS
SUMMARY OF COST ESTIMATES FILED BY NORTHERN BORDER PIPELINE COMPANY AND COMMISSION STAFF
PROJECT SUMMARY
(Thousands of Dollars)

Estimate	March, 1977		March, 1977 - Repriced			Certification Estimate	
Source	NB	Staff	NB[a]	NB	Staff	NB	Staff
Reference	NB-11	S-39	NB-12A	NB-12	S-40	NB-13	S-41
Cost Category	$1975	$1975	$1979	$1979	$1979	$1979	$1979
Direct Costs							
Pipeline System							
Pipeline - 42" O.D.	509,155	505,931	844,812	867,770	772,850	822,206	822,206
River Crossings	4,772	4,772	18,540	19,859	6,478	18,540	18,540
Compressor Stations	4,997	4,997	7,857	8,073	6,623	7,857	7,857
Land Row Permits	13,187	13,187	62,594	64,801	22,807	62,594	32,584
Measurement Stations	2,076	2,076	2,821	2,882	2,706	2,810	2,810
Communications and Supervisory Systems	7,366	7,366	13,913	14,297	9,596	11,077	11,077
Operation and Maintenance Equipment	3,045	3,045	4,734	4,853	4,499	4,734	4,734
Survey and Mapping	2,465	2,465	4,101	3,876	3,204	4,101	4,101
Total	547,063	543,839	959,372	986,411	828,763	933,919	903,909
Indirect Costs							
Study Group and Preliminary Engineering	2,273	2,273	2,273	2,273	2,273	2,273	2,273
Project Management	25,509	25,509	56,904	59,890	34,294	56,904	53,754
Commitment Fee for Debt	9,902	9,902	17,128	17,634	N/A	N/A	N/A
Finance Charge	122,150[b]	122,150[b]	31,506	85,805	88,622	30,442	27,784
Contingencies	35,157	--	62,723	64,574	--	61,023	--
Total	194,991	159,834	170,534	230,176	125,189	150,642	83,811
Total Direct and Indirect Costs	742,054	703,673	1,129,906	1,216,587	953,952	1,084,561	987,720
Government Agency Costs	1,504	1,504	9,698	9,996	2,278	9,630	9,630
Total Capital Costs	743,558	705,177	1,139,604	1,226,583	956,230	1,094,191	997,350

[a]Filed in compliance with Commission Order of January 4, 1980.
[b]AFUDC

Table B

NORTHERN BORDER PIPELINE COMPANY
PRE-BUILD PORTION MARCH 1977 ESTIMATE IN 1979 DOLLARS
COMMISSION ADJUSTMENTS FOR ISSUES RAISED BY STAFF
(THOUSANDS OF DOLLARS)

Reference[a]		Unit	Quantity	Material	Install	NB-12 Total[b]	Adjustments	Adjusted Total	Remarks
	Direct Costs								
C2, C3	Pipeline System: Material	MI.	809.7	603,369	--	603,369	(24,113)	579,256	Use price for TI-1 line pipe rather than for TI-2 pipe.
C1, C4	Installation		--	--	264,401	264,401	(56,711)	207,690	Reduce labor for 43.3% lower productivity.
	Total		--	--		867,770	(80,824)	786,946	
C1, C4	River Crossings	EA.	3	4,694	15,165	19,859	(5,629)	14,230	Reduce labor for 43.3% lower productivity.
C1, C4	Compressor Station	EA.	1	5,959	2,114	8,073	(495)	7,578	Reduce labor for 43.3% lower productivity.
C5	Land ROW Permits	MI.	809.7	--	--	64,801	(41,323)	23,478	Reduce for mineral rights of coal fields.
C4	Measurement Stations	EA.	3	2,274	608	2,882	--	2,882	
C6	Comm. & Supervisory Systems	MI.	809.7	10,136	4,161	14,297	--	14,297	
C6	Operation & Maint. Equip.	L.S.	--	--	--	4,853	--	4,853	
C6	Survey & Mapping	MI.	809.7	--	--	3,876	--	3,876	
	Total Direct Costs		--	--	--	986,411	(128,271)	858,140	
	Indirect Costs								
--	Study Group & Preliminary Engineering		--	--	--	2,273	--	2,273	
C7	Project Management		--	--	--	59,890	(18,197)	41,693	Reduce for cost growth due to non-traditional costs
C8	Commitment Fee for Debt		--	--	--	17,634	(17,634)	--	Included in Finance Charge.
C10	Finance Charge		--	--	--	85,805	(12,119)	73,686	7.64% of adjustments other than Commitment Fee
C9	Contingencies		--	--	--	64,574	(9,120)	55,454	6.1% of adjustments other than Commitment Fee and Finance Charges.
	Total Indirect Costs		--	--	--	230,176	(57,070)	173,106	
	Total Direct & Indirect Costs		--	--	--	1,216,587	(185,341)	1,031,246	
C7	Government Agency Costs		--	--	--	9,996	(3,036)	6,960	Reduce by 30.38% for cost growth.
C11	Total Direct, Indirect & Government Costs		--	--	--	1,226,583	(188,377)	1,038,206	

[a] For discussion of adjustments, see referenced paragraph of Chapter V of text.

[b] Final submission of 2-26-80.

VI. TARIFF AND SHIPPER TRACKING ISSUES

This section of the order addresses the proposed tariff amendments submitted by the shippers for the Northern Border segment of ANGTS. These revised tariffs present the mechanism for shipper tracking of Northern Border costs. This order will govern the provisions of tariffs for costs associated with the import of Canadian gas for transportation through Northern Border. At a later date, we will approve tariff provisions for costs incurred by shippers associated with transporting gas from Prudhoe Bay.

A hearing was held concerning the shippers' tariff proposals on October 23, 1979. After the hearing, the parties and staff agreed on a stipulation which resolved most of the issues. This stipulation was entered into the record. The parties could not resolve six issues. Thus, the Commission must decide these six issues, as well as whether to approve the stipulation and agreement. The parties listed the six issues in the Stipulation and Agreement:

1. Whether Shippers should be allowed to commence collecting from their customers reimbursement for charges paid to Northern Border as soon as those charges are incurred or whether amounts paid to Northern Border prior to commencement of deliveries should be accumulated in a deferred account with reimbursement not commencing until commencement of deliveries by Northern Border;

2. Whether, if deferred accounting is required for amounts paid to Northern Border prior to commencement of deliveries, carrying charges should be permitted on the amounts accumulated in the Shippers' deferred accounts during such period;

3. Whether, in utilizing the "as billed" basis for the purpose of cost classification, allocation and design of Shipper's rates, all charges paid to Northern Border should be classified in the demand component;

4. How and when should changes in line-pack costs be reflected in Shipper rates;

5. Whether ANGTS transportation costs should be allowed to be tracked by United through a Purchase Gas Adjustment Clause;

6. How should the Commission ensure that there will be no overcollection of costs attributable to the tracking arrangements?

In placing the tariff issues before us in perspective, a summary of several pertinent portions of Order Nos. 31 and 31-B is useful.

In Order No. 31 the Commission held that the transporters could commence billing upon completion of the ANGTS. During the period between completion of the entire system and actual transportation of gas, the Commission allowed a minimum bill to be charged, including actual operation and maintenance expenses, current taxes, and amounts necessary to service debt. <u>122</u>/ Upon the initial transportation of gas by the system, the project sponsors will then be allowed to charge an interim rate. The Commission established an interim rate structure to be effective when gas deliveries commence and to terminate on the earlier of the first year of operation or upon attainment of design capacity throughput. The interim rate is to be a fixed unit charge and is to be applied to the actual quantities of gas delivered through the system.

The Commission also addressed the issue of shipper tracking in Order No. 31. It did not resolve the specific mechanisms for shipper tracking. However, the Commission stated that,

> "...it is in basic agreement with the concept that any amounts paid ANGTS under a tariff approved by this Commission will be allowed to be included in the rates of those shippers that are interstate gas pipeline companies, subject to appropriate reconciliation of all other aspects of ratemaking to ensure that there is no overcollection of costs attributable to the tracking arrangements themselves. Interstate gas pipeline companies shipping through the ANGTS will be expected to pay all charges properly due to ANGTS. Any such amounts paid ANGTS will be allowed to be included in the rates of those shippers that are interstate gas pipeline companies.

<u>122</u>/ Order No. 31 at 163.

Allowance of those amounts will require that there is a matching of costs and revenues in order that overcollection or undercollection of fixed costs of the shipper company does not occur." 123/

With regard to the six disputed issues, the Commission has reached the following conclusions:

(1) Shippers will be permitted to flow through Northern Border charges to their customers once gas is being delivered through the portion of the Northern Border to which the charges are related.

(2) Shippers will be permitted to accumulate carrying charges on any ANGTS charges on which the shippers are required to defer collection from their customers;

(3) Shippers will be permitted to reflect all of Northern Border's charges in their demand rates;

(4) Shippers will be required to demonstrate that their rates properly account for line-pack gas costs, and to make appropriate adjustments to reflect any change in proportionate ownership of line-pack gas costs,

(5) Shippers will be required to track separately Northern Border transportation costs and purchased gas costs;

(6) Shippers will be required to demonstrate definitively that their tracking arrangements will not disturb the cost revenue balance in their "base" tariff rates.

123/ Order No. 31 at 150.

VI.A. Tracking Commencement Date

The shippers have proposed tariffs which would permit them to flow through all charges to their customers as soon as they pay charges to Northern Border, even if they pay these charges prior to commencement of gas deliveries. Staff argues that the shippers should not be allowed to commence billing prior to delivery of gas. This issue arises because of the Commission's decision in Order No. 31 to permit the transporters to commence billing upon completion of construction. 124/ Therefore, as there is the possibility of an interim period between completion of construction and commencement of gas deliveries, the question arises whether shippers should be allowed to flow through Northern Border's charges during this period.

Staff argues that the President's Decision prohibits the Commission from permitting shippers' customers from being charged for any costs prior to delivery of gas. The Staff relies on the third finance condition in the Decision which states:

> "Neither the successful applicant nor any purchaser of Alaska gas for transportation through the system of the successful applicant shall be allowed to make use of any tariff by which or any other agreement by which the purchaser or ultimate consumer of Prudhoe Bay natural gas is compelled to pay a fee, surcharge, or other payment in relation to the Alaska natural gas transportation system at any time prior to completion and commissioning of operation of the system." (Decision at 37).

The shippers argue that staff's argument was rejected by the Commission in Order No. 31, that it would be inequitable to require the shippers to pay a minumum bill and then to prohibit them from flowing through the charges on a current basis, and that such a result would place a severe cash drain on the shippers.

124/ In Order No. 31, the Commission stated that billing could commence after the entire system is completed. In Order No. 31-B, the Commission clarified the holding by stating that billing for transportation of Albertan gas could commence when completion of all segments of the facilities to transport Albertan gas shall be completed, tested and proved capable of operation.

In Order No. 31 the Commission stated that neither the Decision nor the legislative history provides certainty in defining the phrase "completion and commissioning of operation." Thus, in specifying a billing date, the Commission considered the broad goals of ANGTA and principles of public utility regulation, as well as the objectives of the project identified in the Decision. The Commission concluded that the condition should not be construed to prohibit the transporters from charging the shippers prior to commencement of gas delivery.

A principal consideration for the Commission in resolving the question of whether the shippers may commence billing their customers when Northern Border commences billing them is whether immediate flow-through is required for financing. Our reading of the testimony and arguments convinces us that immediate flow-through is desirable but not essential.

The Eastern Leg prebuild project will experience almost none of the risks and uncertainties associated with the commencement of gas deliveries from Prudhoe Bay. Under the expected schedules, gas deliveries for the Western Leg prebuild will have started some months earlier. Additionally, the financial exposure of the shippers to the transporters' minimum bill will be different by an order of magnitude from that which will be encountered by shippers on the complete ANGTS.

Given its view that immediate flow-through is not a requirement for financing, the Commission is drawn to the view of the parties representing the customers paying the charges which will be billed by the shippers. The two State PUC's participating in the shipper tariff phase of the proceeding, South Dakota and Minnesota, both favor deferral of shipper charges until gas flows, even if it means exposure to carrying charges.

Another factor affecting the Commission's consideration is the resolution of this issue for the Canadian prebuild segments. In its Phase II order 125/, the Canadian National Energy Board provided that no transportation charges would be allowed for the Canadian segments until gas flows.

125/ National Energy Board, "Reasons for Decision in the Matter of Phase II of a Public Hearing Respecting Tariffs and Tolls to be Charged, the Financing of the Pipeline, and Other Related Matters of Foothills Pipe Lines (Yukon) Ltd.," October, 1979.

Finally, we recognize that delaying billing commencement will increase the charges to be borne by consumers when service commences, because we will allow the shippers to include carrying charges on the amounts contained in their deferred accounts. We do not anticipate that the period of delay between completion of construction and gas deliveries, if there is any delay, will be more than a few months at the most. Therefore, we do not believe that the increased costs to the consumers from delaying billing commencement outweigh the other considerations we have discussed.

For these reasons, the Commission determines that the shippers over the pre-built facilities of the Northern Border system will not be allowed to commence charges to their customers until gas deliveries commence. The Commission recognizes, however, that this resolution may not be appropriate for Alaskan and northern Canadian transportation charges when the entire ANGTS is complete. The Commission instructs its Alaskan Delegate to prepare a report on this issue for use in a future proceeding to consider shipper tracking of Alaskan and Canadian transportation charges.

VI.B. Deferred Accounting and Carrying Charges

Staff also argues that shippers should not be allowed to charge customers carrying charges on amounts accumulated in the shippers' deferred accounts prior to the commencement of deliveries because this would unreasonably shift the financial risks of the shippers onto the consumers. The Northern Border shippers represented in this phase of the proceeding - Northern Natural, Panhandle and United - all argue that carrying charges are essential to full cost recovery in the event that there is any delay between commencement of transportation charges and commencement of tracking. Minnesota and South Dakota argue that carrying charges should only be allowed for those costs found through regulatory review to have been prudently incurred.

Carrying charges will be permitted on Northern Border transportation charges required to be deferred. These charges will be pursuant to a FERC-approved tariff and thus would not require additional regulatory review. However, if carrying charges are sought for other costs incurred in connection with the commencement of deliveries by Northern Border, a review of those costs will be required, as requested by South Dakota. The Commission can see no reason why such a review would need to be lengthy and, thus, believes that the Northern Border shippers need not be concerned about prompt recovery of all legitimate costs.

Deferred accounting with carrying charges will be permitted, not only on any initially deferred accounts, but also on future balances. The Commission will permit this treatment because of the large amount of dollars involved and concomitant possibility of over or undercollection of ANGTS costs by shippers. This treatment will further assure potential lenders of an assured cash flow to service project financing.

VI.C. Classification of ANGTS Costs in Shipper Rates

A key tariff issue is whether all charges paid to Northern Border should be classified in the demand component of the shippers' rates. Staff contends that all charges should be reflected in both the demand and commodity components of the shippers' rates using the methodology approved by the Commission for the shippers. The shippers (Northern Natural, Panhandle, and United) all contend that the transportation charges paid to Northern Border should be reflected in the demand component of their rates. The Commission agrees with the shippers for the reasons stated below.

The Commission's existing method of cost classification for most jurisdictional pipelines, including the three pipelines with which we are concerned here, is the United methodology. 126/ The essence of this methodology has been summarized by this Commission on several occasions. In Opinion No. 21 the Commission stated:

> The United method designates 25 percent of the fixed transmission and storage costs and all "as billed" demand charges to the demand category and all remaining fixed costs together with all variable costs are classified to the commodity category. Costs assigned to the demand category -- sometimes referred to as "demand" costs -- are paid by those customers who have contracted for the right to demand a given quantity at a certain time, whether or not delivery is made. Opinion No. 21, Texas Eastern Transmission Corporation, Docket No. RP74-41, mimeo at 3, n. 5 (1978).

126/ Opinion No. 671, United Gas Pipe Line Company, Docket No. RP72-75 (Phase II), 50 F.P.C. 1348 (1973).

Similar statements appear in other Commission opinions. Opinion No. 819, Consolidated Gas Supply Corporation, Docket Nos. RP73-107, et al., mimeo at 18 (1977); Opinion No. 792, Texas Gas Transmission Company, Docket No. RP75-19, mimeo at 4, 6 (1977). Our PGA regulations are fully consistent with this methodology. Section 154.38(d)(4)(ii) provides:

> Pipeline supplier rate changes shall be applied "as billed" to a pipeline company's two-part rates and shall be applied to a pipeline company's volumetric rates in the manner which maintains the pipeline company's existing one-part rate design.

The United formulation reflects an underlying policy decision that all of an interstate pipeline's own fixed transmission and storage costs (i.e., those costs which have not previously been classified between the demand and commodity components of a rate paid to another pipeline) should be classified 25 percent to the demand component and 75 percent to the commodity component. However, where an interstate pipeline pays another interstate pipeline for purchased gas or for transportation services under a two-part rate which has a demand component, the United formulation requires that all demand charges by the supplier of services be classified by the interstate pipeline recipient of the services in the demand component. Essentially, the billing by the pipeline supplier which reflects the cost classification, allocation and rate design methodology specified by the Commission for that pipeline supplier governs the classification of these costs by the recipient interstate pipeline. This aspect of the United formulation is known as the "as billed" principle.

The "as billed" principle in the United formulation itself embodies several policies. First, the "as billed" principle reflects a judgment that the classification of costs in the rates of the pipeline which renders the service should remain the same as these costs are flowed through by the Commission to customers of that pipeline. By contrast, the alternative of applying the other prong of the United formulation (i.e., classifying demand charges between the demand and commodity components on a 25 percent demand, 75 percent commodity basis) would give effect to the cost classification, allocation, and rate design methodology prescribed for recipient interstate pipelines and would result in successively greater allocations to the commodity component of interstate pipeline rates as the costs are flowed through. This result would be neither reasonable nor consistent with the underlying principles supporting the United methodology. A second and, in this context, more important policy underlies the "as billed" principle. The cost classification, allocation, and rate design methodology of the interstate pipeline which performs transportation and other services is predicated on and reflects the service obligation and relationship between that interstate pipeline and the recipients of those services. This cost classification methodology and relationship should not be affected, altered, or diluted by the methodology and relationship which govern services provided by the recipients of those services. The "as billed" principle accomplishes that result and, thus, maximizes the importance of the Commission's cost classification decisions concerning services provided by interstate pipelines.

These principles have relevance here. A decision on this issue should not, as staff contends, be based on the cost classification methodologies employed by United, Panhandle, and Northern Natural for transmission and storage costs incurred by those companies. The costs with which we are concerned here will have been billed by Northern Border, a jurisdictional pipeline company, to these three pipeline companies. It is the relationship between Northern Border and these three pipelines, not the relationship between these three pipelines and their customers, which must be examined. To focus on the relationship between these three pipelines and their customers is to focus on and attribute importance to irrelevancies which, in these circumstances, cloud rather than aid the Commission's analysis. These irrelevancies include, for example, peak day usage, the allocation between jurisdictional and non-jurisdictional customers, and contract demand billing determinants on the systems of United, Northern Natural, and Panhandle. The Commission is not concerned with the operations and services provided by United, Northern Natural, and Panhandle; the Commission is concerned with the proposed operations and services of Northern Border. In short, the Commission believes that the "as billed" principle should govern the cost classification of transportation charges billed by Northern Border to the shippers and that the proper classification of Northern Border's charges as either "demand" or "commodity" charges and the service relationship between Northern Border and the shippers should guide our decision.

There remains the matter of the proper classification of Northern Border's transporation charges to the shippers as "demand" charges or "commodity" charges. Resolution of this matter is complicated by the fact that Northern Border has a cost of service tariff and will not bill the shippers in "demand" or "commodity" units which are denominated as such. Moreover, while the Commission has specified Northern Border's tariff form, the Commission has not expressly specified the method of cost classification for Northern Border.

These concerns and limitations do not, however, require that the Commission ignore the billing practices of Northern Border and focus on the cost classification methodology employed by the interstate pipeline recipients of Northern Border's service on the theory that cost of service tariffs, without "demand" or "commodity" charges as such, necessitate this approach. To do that would be tantamount to a Commission decision to ignore the provisions of the cost of service tariff and to treat all such tariffs the same regardless of the specific provisions thereof. The Commission does not prescribe these tariffs in certificate proceedings only to have the provisions and consequences thereof rendered nugatory when these costs are classified in the rates of interstate pipeline recipients of service. As noted above, the relationship between Northern Border and the interstate pipeline shippers is critical and must be examined. It is far preferable for the Commission to examine Northern Border's billing practices and charges, determine whether Northern Border's charges can properly be considered as "demand" or "commodity" charges, and then apply the "as billed" principle of cost classification to the interstate pipeline shippers. This procedure is superior to the distinctly second best solution, urged by staff, which rejects the relevance of Northern Border's tariff and billing practices and effectively, but incorrectly, treats Northern Border's transportation costs as fixed costs incurred not by Northern Border in the first instance but rather by the three interstate pipeline recipients of Northern Border's services. 127/ To treat Northern Border as if it were the shippers would be to ignore our certificate decisions, and the project financing central to this proceeding, both of which indicate that Northern Border is a separate and distinct entity from these three shippers.

While the Commission has not expressly specified the method of cost classificaiton for Northern Border, the Commission believes that all facts necessary to make a judgment concerning whether Northern Border's charges are "demand" or "commodity" charges are in the record. The Commission has previously addressed Northern Border's tariff form in the Order No. 31 series of orders. Northern Border's pro forma tariff is in the record; testimony on tariff issues is part of the record. Under the tariff, Northern Border will bill each shipper for that portion of the total cost of service which is properly allocated to the shipper under a Mcf-mile methodology. Since each shipper will own its proportionate share of the linepack and will provide shipper used gas and compressor fuel, virtually all of Northern Borders' cost of service will consist of fixed costs including depreciation, return, and taxes. As noted, above, these costs will be allocated to each shipper under a Mcf-mile methodology where the Mcf portion refers to the contracted quantity which each shipper has a right to ship under Northern Border's tariff.

The essence of demand charges for transportation services is the contractual right to require that natural gas be shipped up to a specified limit. Commodity charges, on the other hand,

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127/ There may be situations which arise in connection with cost of service tariffs where the relationship between the interstate pipeline which provides the service and the interstate pipeline recipients of the service is such that it could be reasonable to consider all costs incurred by the interstate pipeline recipients as if, these costs were the receipent' own transmission and storage costs. In those cases either the "as billed" prong or the 75/25 prong of the United formulation might reasonably be applied. In the case of the prebuilt ANGTS with which we are concerned here, Northern Border's identity is sufficiently separate from that of the shippers so that it would be unreasonable to attribute the costs billed by Northern Border as if these costs were the shippers' own transmission and storage costs in the first instance.

are based on volumes of natural gas transported. Northern Border's charges under its cost of service tariff do not vary based on the amount of natural gas shipped for United, Panhandle and Northern Natural. The charges to these three interstate pipeline will be the same, whether or not these interstate pipelines actually ship natural gas through Northern Border in the contracted quantities. Moreover, the costs which Northern Border reflects in these charges are fixed costs which do not vary with actual throughput.

The behavior of Northern Border's costs with throughput and the provisions of Northern Border's tariff both lead us to one conclusion. 128/ All charges by Northern border to these three interstate pipelines can and should be characterized as "demand" charges. At best, only an insignificant portion of these charges, both under Northern Border's billing procedures and as a matter of cost incurrence, could be recognized as a "commodity" charge. Given these conclusions and the related conclusion that the "as billed" principle should govern classification by the shippers of Northern Border's charges which are classified as "demand" charges, the Commission concludes that all charges by Northern Border should be reflected in the demand component of the interstate pipeline shippers' rates.

VI.D. Northern Border's Method of Depreciation and Classification of Northern Border's Depreciation Charges in Shippers' Rates

Staff, noting that Northern Border has proposed to base its depreciation charges on a unit-of-throughput method, contends that, by definition, "these depreciation costs incurred by the shipper would be automatically classified as 'variable' costs and assigned 100% to commodity." Based on that contention, staff urges the Commission that "if it allows the shippers to classify 'fixed costs' on an 'as billed' basis as

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128/ Given the billings provisions which compel the conclusion that these charges are "as billed" demand charges, the Commission is not really required to examine the behavior of costs with throughput or to engage in all the other detailed procedures associated with costs which normally attend rate determination where two part stated rates are involved. However, the behavior of costs with throughput does support our determination.

demand costs then it at least must require that the unit-of-throughput depreciation costs be assigned to commodity on an 'as billed' basis." 129/

The premise of the staff position apparently is that if the depreciation component of Northern Border's charges is not based upon a fixed annual percentage rate of depreciation accrual, that component of the charge is not fixed *per se*, but is variable. Most pipelines' depreciation expenses are computed on the basis of fixed annual percentage accrual rates and are classified as fixed costs within the pipelines' cost-of-service. To this extent, the Commission agrees that Northern Border's proposed depreciation method is different.

As a general rule, the Commission will continue to require that gas pipelines' depreciation expenses be computed on the basis of fixed annual accrual rates. This approach is dictated by, among other things, the operating nature of the pipelines. For example, most pipelines are dependent upon a multitude of suppliers (e.g., producers and other pipelines) for their gas throughput. Additionally, they are not designed for the transportation of only specifically identified reserves or precisely dedicated volumes. Most pipelines, therefore, differ significantly in their design, intended purpose, and actual operation from that of Northern Border.

Where a pipeline's operations are totally, or very substantially, tied to export authorizations for specific quantities of gas by another country, the Commission concludes that a fixed annual rate of depreciation accrual is not required and that the unit-of-throughput method of depreciation charges is acceptable. This method has been allowed for PGT, which is essentially dependent upon Canadian export authorizations for its operations, and the Northern Border prebuild operations will be substantially similar to PGT's. As previously stated, 130/ the Commission approves Northern Border's "unit-of-throughput" method of depreciating prebuild costs.

129/ Staff reply brief at 5 and 6, footnote 7.

130/ *Supra*, at 18.

Although the Commission approves Northern Border's unit-of-throughput depreciation method, the Commission does not agree with staff that depreciation charges resulting from that method are necessarily variable costs that must be classified 100 percent to the commodity category. Depreciation expenses are permitted in rates to provide for the recovery of capitalized costs. The capitalized costs are fixed amounts that the pipeline has already incurred. The true behavior and nature of incurrence of capitalized costs is fixed. That is, the level of those costs will not vary with throughput, but will remain constant. The Commission agrees that Northern Border's method of recovery of capitalized costs through its charge to shippers has some "variable" connotation. However, the costs are "fixed" from a cost incurrence and cost behavior viewpoint. All of Northern Border's charges, including the portion of those charges attributable to depreciation, shall be classified in the shippers demand rates in accordance with the procedures discussed herein.

VI.E. Assurance of Lack of Over-Recovery or Under-Recovery of Costs as Result of Tracking Arrangements

In expressing basic agreement in Order No. 31 with the concept of tracking the ANGTS charges by shippers, the Commission stated that any tracking should be "subject to appropriate reconciliation of all other aspects of ratemaking to ensure that there is no overcollection of costs attributable to the tracking arrangements themselves." The Commission's policy was summarized as follows:

> "... Interstate gas pipeline companies shipping through the ANGTS ... will be expected to pay all charges properly due to ANGTS. Any such amounts paid ANGTS will be allowed to be included in the rates of those shippers that are interstate gas pipeline companies. Allowance of those amounts will require that there is a matching of costs and revenues in order that overcollection or undercollection of fixed costs of the shipper does not occur." (Order No. 31 at 150)

The Commission's policy regarding the ANGTS charges, therefore, provides an assured flow of revenue to ANGTS equal to its cost-of-service, provides for full recovery of those amounts paid to ANGTS by interstate pipeline companies, and provides consumer protection against over-payments to the interstate pipeline shippers. Recovery by Northern Border of its cost-of-service will result from the tariff provisions approved in Order No. 31. To provide assurance of full recovery by interstate pipeline shippers of amounts paid Northern Border and protection against excess charges to those shippers' customers, the Commission will require (1) a demonstration by the shippers, prior to the inclusion of any Northern Border costs in their rates, that their base tariff rates properly account for Northern Border volumes and revenues, as well as Northern Border costs, and (2) that the shippers' tariffs provide for a deferred accounting and recovery mechanism for Northern Border charges. The shippers will be permitted to make rate adjustments to track changes in Northern Border charges coincident with their normal periodic PGA rate changes. 131/ Subsequent to the initial inclusion of Northern Border charges in a shipper's rates, the shipper's base tariff rates will be subject to review under the provisions of Sections 4 and 5 of the NGA.

Each of the shippers participating in this phase of the proceeding has tendered *pro forma* tariff sheets which provide for deferred accounting of payments and recovery of the Northern Border charges. Contingent upon the establishment of cost allocation factors which properly account for the introduction of the Pan Albertan gas supply into their respective systems, the Commission views the shippers' proposed deferred accounting and recovery mechanisms as appropriate.

There is disagreement among the staff, South Dakota, Minnesota and the shippers relating to the procedures to be followed in making initial rate adjustments to reflect inclusion of the Northern Border charges in the shippers' rates. There is also inconsistency in the procedures proposed by the shippers. The Commission's general policy will be to require that each shipper demonstrate, in accordance

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131/ The Commission notes that Northern Natural's PGA filings are made annually, but that Northern Natural proposes semi-annual filings to track Northern Border charges. Northern Natural's proposed semi-annual tracking of Northern Border's charges is consistent with the proposals of the other shippers and is approved.

with Section 4(e) of the Natural Gas Act and in accordance with the procedures set forth in section 154.63 of the Commission's Regulations, that its base rates properly and fully account for all costs, volumes, and revenues associated with the ANGTS gas supply.

In order for a pipeline to include a PGA provision in its tariff, the Commission's Regulations require the showing of an appropriate cost-revenue balance in the base tariff rates from which subsequent adjustments will be made. Section 154.38(d)(4)(i) of the Regulations states:

> "(i) The proposed PGA clause shall be accompanied by a cost study in conformity with the requirements of § 154.63. This study must be based upon actual costs for the 12 months of most recently available actual experience and may include annualization for changes which actually occurred in the 12 month period. If a cost-of-service study having a test period ending less than 12 months prior to the date of submission of the proposed PGA clause is on file in another docket, the cost study may be utilized in lieu of filing a cost study with the proposed PGA clause."

The above described cost study is based upon actual costs and operations and annualization of changes which have already occurred. It does not provide for inclusion of so-called "known and measurable changes" which will occur subsequent to the twelve-month "base" period. In contrast to the above quoted portion of the Commission's Regulations, section 154.63(e)(2), which pertains to general rate change applications (i.e., changes to base rates), provides that a cost/revenue filing:

> "... shall be based upon a test period which shall consist of a base period of 12 consecutive months of most recently available actual experience, adjusted for changes in revenues and costs which are known and measurable with

> reasonable accuracy at the time of the filing, and which will become effective within nine months after the last month of available actual experience utilized in the filing, but in no event shall such test period extend more than nine months beyond the date of filing; Provided, however, that for good cause shown, upon application of the natural gas company made to the Commission 30 days in advance of the rate filing, the Commission may allow reasonable deviation from the prescribed test period..."

The shippers propose to make rate filings, or submit cost-revenue studies prior to implementing rates, which include the Pan Albertan purchased gas costs and Northern Borders' transportation charges. Northern Natural and Panhandle propose to make rate filings in accordance with the requirements of section 154.63 and to make adjustments to actual costs and operations to account for the ANGTS costs and gas supply. United's proposal is more similar to the filing provisions of section 154.38.

Staff states:

> "The Commission has now received four different procedures for ensuring that there is no overcollection of costs attributable to the tracking arrangements. Staff recommends the Commission adopt one method, which should be applied to all ... shippers..." 132/

> "The proposals of Northern..., Panhandle..., and Staff... are relatively similar, with each proposal generally ensuring that there is no overcollection of costs attributable to the tracking arrangement. On the other hand, Staff contends that United's proposal... does not ensure that there will be no overcollection of costs."

132/ Staff reply brief at 7-8.

Staff contends its proposals is superior to those of Northern Natural and Panhandle, because it is less complicated and easier to administer than Northern Natural's proposal, and because it is more detailed than Panhandle's and therefore eliminates controversy over what is actually required. According to staff, the proposals of Northern Natural, and Panhandle, as well as the staff proposal, all require the inclusion in a cost-revenue study of the costs and revenues associated with the Pan Alberta volumes. Staff asserts United's method does not provide for such inclusion and, therefore, should be rejected.

Northern Natural states that it and South Dakota "have negotiated a certificate condition that will accomplish the Commission's purposes while at the same time assuring Northern and the lenders to and owners of Northern Border that Northern will be able promptly to pay Northern's bills." 133/ The proposed certificate condition seems to provide several options to Northern Natural to select what it perceives at the time of the initial ANGTS rate adjustment to be its most efficient and advantageous course of action. Its options would vary from using a general rate change application on file, updating such an application, making a new general rate change application, or submitting a study based on the same principles and procedures used to develop the total system cost of service underlying the Base Tariff Rates.

Staff objects to the Northern Natural-South Dakota proposal on two grounds: First, staff argues that Northern Natural should not be permitted to update the record in a pending rate case to reflect inclusion of the ANGTS volumes and costs. Staff would require the filing of a new cost/revenue study rather than permit the updating of an existing record. Second, Staff argues that Northern Natural should be permitted to file only one cost/revenue study and that the study should be based on "annualized" Pan Alberta volumes.

Northern Natural contends staff's position is incorrect because it "assumes erroneously that the flow of Pan Alberta volumes during the first twelve months will equate perfectly to annualized Pan Alberta supplies." 134/ The initial cost and

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133/ Northern Natural initial brief at 9.

134/ Northern Natural reply brief at 6.

revenue study should not be limited to annual volumes, according to Northern Natural, because there is a good possibility that the actual volumes during the first twelve months will vary from annualized Pan Alberta supply volumes. Northern Natural suggests that "it may well be that an additional study utilizing some other projected volume would be helpful to reach a proper conclusion on the question of overcollection of costs." Based on that possibility, Northern Natural concluded that it should not be foreclosed, at this time, from presenting "studies that may well be relevant and which it would be willing to prepare." 135/

Panhandle has proposed two options for providing a cost/revenue comparison prior to the effectiveness of its initial ANGTS rate adjustment. Under its proposal, Panhandle would either (1) adjust a pending Section 4 rate filing "to reflect the annual costs, volumes and revenues attributable to the new Canadian gas supply," or (2) file a new general rate increase including the annual costs, volumes and revenues attributed to the new Canadian gas "to be effective concurrently with Panhandle's initial ANGTS rate adjustment." 136/

The only difference between Panhandle and staff appears to be related to the updating of a pending Section 4 rate filing. Rather than updating a pending filing, staff would require Panhandle, as well as the other shippers, to file a new Section 4 rate change application.

United disagrees with the staff's position, claiming that staff would use the advent of prebuild volumes as a means of requiring United to present a full rate case wherein Staff could place in issue every aspect of United's rates. The requirement of a Section 4(e) rate case, according to United, goes far beyond the rate assurance contemplated in Order No. 31. United states that it is in agreement with the Commission's concern that "the addition of the [prebuild] volumes to United's system supply does not result in significant overrecovery of the prebuild project expense." 137/

135/ Northern Natural reply brief at 6-7.

136/ Panhandle initial brief at 10.

137/ United's reply brief at 10-11.

All that needs to be addressed, in United's view, are the billing determinants underlying the company's base charges in its existing rates.

The Commission does not accept United's characterization of Order No. 31. In that order, the Commission described its concern as more than whether tracking would result in "significant overrecovery of the pre-build project expense," as United suggests. In Order No. 31, the Commission's concern went also to the fixed costs inherent in commodity rates and whether increased sales by a shipper resulting from added gas supply would produce excess revenues.

The Commission understands United's concern with having to make Section 4(e) rate filings as a prequisite of tracking Northern Border charges. In the Commission's view, however, any added burden to United in making an appropriate filing is outweighed by considerations of consumer interest in paying just and reasonable rates. The Commission agrees, however, that the central issues on which to focus in establishing rates which provide for recovery of the Northern Border charges are (1) whether the portion of the rates attributable to the Northern Border charges will produce revenues equivalent to those charges, and (2) whether the base tariff rates are designed upon volumes which fully account for the introduction of the Pan Albertan gas supply into the shippers' systems. The Commission also notes that Northern Natural and Panhandle, having agreed to making such filings, apparently do not view the filings as an onerous requirement.

The Commission does not see at this time the necessity for the duplicate or alternative cost/revenue studies that would be provided for under the Northern Natural proposal. Northern Natural, itself, acknowledges that only one study may be necessary. If the pre-delivery operations can be projected with reasonable certainty at the time the filings are made, the "one-study" approach would be adequate. The Commission, therefore, expresses a decided preference for one filing from each shipper. 138/ Accordingly, the Commission

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138/ This preference for one filing means that only one cost-revenue study will ever be required for the prebuild shippers; subsequent checks can be made in the course of general rate change proceedings and normal PGA filings. Another cost-revenue study would, of course, be required when Alaska gas starts to flow.

encourages the shippers to develop studies which are normalized to achieve a close match between costs and revenues but which also will avoid the necessity for multiple studies or filings. Such an approach is consistent with the rate surcharge and deferred accounting procedures proposed by the shippers and approved by the Commission.

In the Commission's view, Panhandle's proposal will produce the needed results of measuring and accounting for the full rate effect of the commencement of charges and volumes from the Northern Border. 139/ Northern Natural's proposal is similar in certain respects to Panhandle's, but the Northern Natural proposal has added, and unnecessary, provisions. Therefore, the Commission declines to adopt the Northern Natural/South Dakota stipulation 140/ as a certificate condition. The method proposed by Panhandle is straight-forward and substantially satisfactory, and it is adopted as modified below. Accordingly, the Commission will require that the following condition be met prior to the inclusion in the shippers' rate of the initial ANGTS Rate Adjustment:

1. If a shipper has a pending general rate increase pursuant to Section 4 of the Natural Gas Act which can be adjusted to reflect the annual costs, volumes and revenues attributable to the Pan Alberta gas supply, such general rate increase shall be used to demonstrate that the shipper's base tariff rates generate revenues equal to jurisdictional annual cost of service, as adjusted. Base tariff rates that meet this condition, together with the deferred accounting mechanism, will ensure that there is no overcollection or undercollection of Northern Border costs.

139/ See, Panhandle initial brief at 9-10.

140/ "Joint Motion of Northern Natural Gas Company and South Dakota Public Utilities Commission for Cancellation of Hearing and Acceptance of Stipulation." The Motion was also supported by the Minnesota Public Service Commission.

2. If a shipper does not have a pending Section 4 general rate increase which can be adjusted as described in paragraph 1, above, the shipper shall file a general rate increase including the annual costs, volumes and revenues attributable to the Pan Alberta gas supply to be effective concurrently with the initial ANGTS Rate Adjustment.

VI.F. Line Pack Gas Costs

The Commission addressed the issue of line-pack costs in Order No. 31, stating,

> "The Commission will, therefore, defer the specification of any particular recovery mechanism pending receipt of the ANGTS cost flow-through proposals by individual shippers based upon their particular circumstances. Such proposals should include methods for recovery of line-pack costs that will reflect actual cost incurrences based upon actual line-pack obligation." (Order No. 31 at 212)

The shippers responded to the Commission's directive in various ways. Panhandle provided a tariff provision which accounts for changes in line pack costs. United has proposed no tariff provision to reflect actual line pack cost incurrences. United proposes that any reduced cost attributable to reduction in line-pack gas responsibility will be reflected in United's next succeeding rate change filing submitted to the Commission. United also notes that the per Mcf reduction resulting from changes in line pack responsibility would be so small it would be lost in the rounding process. Northern Natural concurs in this view. Staff argues that the shippers should be required to credit or debit the ANGTS tracking provision-deferred account. It argues that, if the cost-of-service is only adjusted in a Section 4 rate case when line pack costs decrease, there will be an overrecovery of revenues.

The shipper responses do not diminish the Commission's concerns. Given the recent increases in the Canadian gas export prices, the Commission attaches even greater importance to this issue. Additionally, the precise costs attributable to line-pack gas once Alaskan gas commences to flow is unknown.

Furthermore, the ownership of line-pack gas throughout the life of the ANGTS can not be projected.

Based on the above considerations, the Commission will require that the shippers demonstrate that their rates properly account for line-pack gas costs and that the shippers make appropriate rate adjustments, and restitution as necessary, to reflect any changes in their ownership of line-pack gas. Accordingly, the Commission will attach the following condition to any certificate issued to a shipper using the Northern Border prebuild facilities:

> Line Pack Gas Costs: In any filing to reflect Norther Border's charges, the shipper shall demonstrate that line pack gas costs are properly accounted for and reflected in rates. In the event that the shipper's level of line-pack gas costs have changed from the level of line pack gas costs previously included in its rates, the shipper shall further demonstrate that appropriate restitution has been provided for any excess revenues collected from its jurisdictional customers.

It is not the Commission's intention to create complications or difficulties for shipper recovery of line-pack gas costs. The Commission contemplates that the shippers' rates will provide for full recovery of all line-pack gas costs prudently incurred. The Commission will require, however, the necessary measure of consumer protection to assure that the shippers' rates reflect only the appropriate level of line-pack costs.

VI.G. Separate Tracking of Purchased Gas Costs and ANGTS Transportation Costs.

Whether separate tracking of purchased gas costs and Northern Border transportation costs should be required is apparently no longer an issue. All parties have agreed to or stated the acceptability of the tracking of purchased gas costs separately from the tracking of Northern Border costs. The Commission will require that the shippers' tariffs provide for separate tracking.

VII. MISCELLANEOUS ISSUES

A. IROR Issues

1. Inflation Adjustment Mechanism

Two issues concerning the inflation adjustment mechanism required by the incentive rate of return procedure were considered in the hearing. The first concerns the labor cost indices to be used. In response to concerns expressed by Northern Border about the labor cost indices specified in Order No. 31, the Commission in Order No. 31-B stated that:

> "... the Commission will reserve a final decision on the exact specifications of the labor component of the composite index until the sponsors have filed their Certification Cost and Schedule Estimates. With the filing of the Certification Estimates, the Commission expects the sponsors to specify in detail the quarterly or annual cost categories for labor and measure of labor wage rates for each cost category that they propose. After reviewing the specific proposals submitted by the sponsors concerning labor indices, the Commission will approve or modify these proposals in conjunction with its consideration of the Certification Estimates." (p. 30)

Northern Border, in Exhibit NB-15, has proposed nine labor categories and measures of wage rates for each category taken from the National Pipe Line Agreements and the Richardson Construction Cost Trend Reporter. Staff has determined that the specific labor indices are reasonable as long as they are used on a 48-state basis. 141/ The Commission concurs and approves the labor categories and measures of labor wage rates proposed by Northern Border.

The second issue was raised in staff's initial brief (at 96-97). Staff interpreted certain examples of an inflation adjustment mechanism used by Northern Border in Exhibit NB-17 as being contradictory to Condition 5 in Order No. 31 (at 241). Condition 5 specifies the use of a "composite index calculated as a weighted average of existing published indices or price data." The examples used by Northern Border show each cost category being deflated separately by

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141/ Tr. 754.

the measure of the inflation for that category rather than using a composite index. Northern Border in its reply brief admitted that Exhibit NB-17 was in error and not in compliance with Order No. 31. 142/ Northern Border submitted a second example of an inflation adjustment mechanism as an Appendix A to its reply brief. The Commission has reviewed the second example and concludes that it is in compliance.

VII.A.2. One-Time Adjustment to Rate Base

Staff has argued that the period for calculating the one-time adjustment to rate base, required by the incentive rate of return mechanism as set forth in Orders No. 31 and 31-B, should be the same as the amortization period for the rate base including the one-time adjustment. The amortization period recommended by the staff is 27 years. Northern Border argued that Order No. 31 requires the use of a 25 year period for calculating the one-time adjustment even though the useful life or amortization period of the facilities may be greater or less than 25 years.

The Commission's intent in Order No. 31 was to require a 25 year period for calculating the one-time adjustment. The Commission established the fixed 25 year period in order to reduce uncertainty and future controversy over the calculation of the one-time adjustment even though some inaccuracy may result. The Commission first adopted the 25 year period in Order No. 17, 143/ in response to criticism by project sponsors that "there is no simple and clear cut means of implementing the one-time adjustment to rate base." 144/

VII.B. Tariff Adjustments Pursuant to Orders No. 31 and No. 31-B

The Commission provided in Orders No. 31 and No. 31-B for periodic review of the rate of return and for adjustments to the project company tariffs, but did not set a fixed interval for such reconsiderations.

142/ Order No. 31 at 25.

143/ Order No. 31 at 13.

144/ Comments of Alaskan Northwest Natural Gas Transportation Company, A Partnership, October 13, 1978, at 13.

Staff recommended that the Northern Border prebuild project rate of return be subject to initial review three years after the billing commencement date, with subsequent reviews conducted every three years thereafter. This proposal was based on Commission precedent, as rate reviews are required at a frequency of not more than three years pursuant to the Commission's Regulations pertaining to PGA provisions. Northern Border agreed to this proposal and filed with the Commission a supplemental tariff sheet to that effect. The Commission approves this proposed review schedule as stipulated by staff and Northern Border.

VII.C. Quality Standards for the Gas

In Order No. 31, the Commission approved all but one of the quality standards for the gas to be transported, with respect to both the Northern Border and Alaska segments. 145/ The one exception was the standard for carbon dioxide, 146/ for which the Commission requested additional data. 147/ A substantial amount of data was submitted, almost all of which was focused primarily on the Alaska segment standard. Because of the relationship of the carbon dioxide standard to matters pertinent to the financing of the Alaska segment, and inasmuch as those financing matters are currently a subject of negotiation, the Commission has held its carbon dioxide inquiry in abeyance.

Certification of the Northern Border prebuild project however, requires us to approve a carbon dioxide standard for the gas to be imported from Canada for transportation

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145/ Order No. 31 at 213-215. The water and sulfur standards were approved "subject to any revisions that may be required to comport with the final pipeline system design." The final design will be submitted to the Federal Inspector for approval subsequent to the issuance of the certificates herein.

146/ Order No. 31 at 151-152.

147/ "Order Requesting Submission of Data, Views, and Comments" (Docket Nos. RM78-12 and RM79-19) (issued May 16, 1979).

through the Northern Border segment. We make this determination without prejudice to any future determination to any further determination as to carbon dioxide standards for the transportation of gas from Alaska.

Northern Border's *pro forma* tariff requires that "[t]he gas shall not contain more than two percent by volume of carbon dioxide." 148/ Standard U.S. pipeline practice is to allow a carbon dioxide content of up to three percent. The prevalent Canadian standard, however, is two percent, and the Canadian gas to be transported through Northern Border will satisfy that standard. Accordingly, the Commission will approve the two percent standard proposed by Northern Border. As indicated above, out determination applies only with respect to transportation of Canadian gas in connection with the prebuild project.

VII.D. Downstream Transportation and Exchange Agreements

Northern Natural will receive into its system all 800,000 Mcf per day of gas transported by Northern Border and purchased by itself, Panhandle, and United. It will receive 25,100 Mcf per day of its gas at a point in South Dakota, and 75,400 Mcf per day of its gas at a point in Minnesota. The remaining 699,500 Mcf per day for itself, Panhandle and United will be received into its system near Ventura, Iowa.

Northern Natural maintains that it has the ability to perform the services proposed with the addition of relatively minor facilities. 149/ Its agreement with Panhandle calls for it to redeliver the 150,000 Mcf per day to Panhandle at an interconnection point on Northern's system at Kiowa County, Kansas. The gas will be delivered by transportation and displacement, and Panhandle would pay Northern Natural a monthly demand charge of $301,294. 150/ This charge will change in accordance with the negotiated formula as Northern Natural's cost-of-service changes. In our view this exchange arrangement is in the public interest.

Northern Natural proposes to utilize United's gas, and in exchange to deliver thermally equivalent volumes to United from Northern Natural's reserves in the Gulf Coast supply

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148/ Section 51.6 of the General Terms and Conditions.

149/ The total cost of facilities requested is $980,080 (Exhibit No. NNG-2).

150/ The charge is based on Northern Natural's cost of service per 100 miles of transportation. Since a substantial portion of the service will be displacement a factor of .25 was applied to Northern's Natural's cost of service.

area. No charge is associated with this arrangement. Staff states that it favors the concept of a Northern Natural - United exchange, but alleges that there is no record support that United's volumes can be delivered without additional facilities or significant transportation costs.

Northern Natural and United are seeking approval of their proposed exchange agreement on the basis that there is no need for additional facilities and that no transportation costs are involved. Our approval for the proposed exchange agreement is premised upon these facts. Accordingly, we approve the proposed exchange agreement between Northern Natural and United, provided that no significant transportation costs are involved and that there is no need to construct additional facilities to accomplish the exchange.

VII.E. Certification of ANB Gas Company

ANB Gas Company, which is a wholly owned subsidiary of United, requests that the Commission grant it a certificate of public convenience and necessity to ship 450,000 Mcf of gas per day through Northern Border's facilities. United assigned to ANB its right to purchase the gas involved.

Staff contends that ANB has failed to justify the certificate requested. As staff points out, ANB has no full time employees, and will perform no physical service nor charge United for any service. According to staff, ANB's services could be performed by United.

We agree with staff that the record in this proceeding does not support a finding that the public convenience and necessity requires the granting of a certificate to ANB. Accordingly, the application will be denied.

VII.F. Executive Order 10485

In its brief, Northern Border requests that the Commission approve the construction of facilities at the international border near Port of Morgan, Montana, pursuant to Executive Order 10485. 151/ As staff points out, Northern Border has not filed any application pursuant to Executive Order 10485. (See section 153.10 *et seq*. of the Commission's Regulations, 18 C.F.R. Part 153.) Executive Order 10485 requires the Commission to obtain the views of the Secretary of State and the Secretary of Defense. Thus, the application must be in

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151/ With respect to the facts presented herein, the function of implementing Executive Order 10485 was delegated to the Commission pursuant to Department of Energy Delegation Order No. 0204-8 (42 F.R. 61491).

a form that clearly identifies for them the border facilities involved. Accordingly, the certificates issued herein will be conditioned upon Northern Border filing an appropriate application and our finding that the construction of facilities at the Canadian/U.S. border to receive the authorized volumes satisfies the requirements of Executive Order 10485.

VII.G. Environmental Assessment

In its initial brief, Northern Border proposes to deviate from the route approved in the Decision in order to avoid the Ordway Memorial Prairie and to follow a route (the Dunn Center Alternative) that would avoid certain coal deposits in North Dakota. These changes would add about 12 miles of pipeline to the prebuilding proposed by Northern Border. The remainder of the Northern Border prebuild route is unchanged from the route evaluated in the Alaska Natural Gas Transportation System: Final Environmental Impact Statement (FEIS), published by the Department of the Interior (DOI) and Federal Power Commission in March 1976.

VII.G.1. Ordway Memorial Prairie Alternate

The Ordway Memorial Prairie (Ordway) is a 7,000-acre tract of land in McPherson County, South Dakota, which was designated for preservation by the Nature Conservancy in July 1975. The original routing would have traversed Ordway for approximately 19,000 feet.

Northern Border's alternate route avoids Ordway and is consistent with the suggestion of DOI in the FEIS. In a September 11, 1979 letter to the FERC, the U.S. Fish and Wildlife Service concluded that prebuilding the Northern Border project, including the Ordway Alternate, would not affect any endangered species. Accordingly, we conclude that the Ordway Alternate route as proposed by Northern Border is preferrable to the original route because it avoids the Ordway Memorial Prairie.

VII.G.2. Dunn Center Alternate

Approximately 60 miles of the originally proposed Northern Border route in Dunn, Mercer, Oliver, and Morton Counties, North Dakota, would cross lands identified by the United States Geological Survey, the State of North Dakota Geological Service and various coal companies as having potential for commercial coal development using surface mining. Several major coal fields have been identified there: the Dodge-Halliday field in Dunn County, the South Beulah field in Mercer and Oliver Counties, and the Salem Field in Morton County.

The Dunn Center Alternate now proposed by Northern Border would avoid nearly all known major coal deposits in this region, thereby significantly reducing Northern Border's cost of right-of-way acquisition and the long-term unavailability of the coal which would result if the pipeline crossed the coal fields.

Our advisory staff has prepared an environmental assessment of the alternate routes and has reached the following conclusions:

A. The general area of both the proposed route and the Dunn Center Alternative is geologically stable.

B. The amount of highly erodible soils is essentially the same for both routes. 152/

C. The vegetation and wildlife along the proposed route are characteristic of the types of ecosystems and habitats found along the Dunn Center Alternate.

D. The construction of a pipeline within the Dunn Center Alternate corridor would not affect listed endangered or threatened species. 153/

E. Impacts from constructing the pipeline across croplands would be minor, since these areas may be readily returned to crop production.

F. It is unlikely that overall changes in species composition and habitat types would occur as a result of pipeline construction within the alternative corridor. The Dunn Center Alternate route could cause a greater temporary loss of crops because it would cross more irrigated land, but this loss would be minimal.

The applicant has submitted several mitigation proposals for its original route, including a wetland restoration plan, erosion control plan, and measures to mitigate impact to hydrologic features, water crossings, and the aquatic environment. If the applicant uses these same measures to construct

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152/ However, there are more saline soils with a low revegetation potential along the Dunn Center alterntive than along the proposed route. This difference would be mitigated by Northern Border's proposal to use revegetation and erosion control techniques that are specific for each soil type in restoring the right-of-way.

153/ The U.S. Fish and Wildlife Service concurred with this conclusion in its letter to the Commission of February 8, 1980.

the alternate pipeline, impact to the aquatic environment, hydrologic features, and streams and rivers should be short term, and should not permanently degrade either surface water or groundwater quality.

Many of the environmental impacts described for the proposed route in the FEIS would be similar to pipeline construction impacts within the Dunn Center Alternate corridor. Northern Border has indicated that many of the construction impacts in the alternate corridor would be lessened by the same mitigation measures proposed for the original route.

In addition, Northern Border's supplemental environmental impact assessment for the Dunn Center Alternate corridor indicates the applicant's intention to select a final alignment that would avoid sensitive environmental areas. We believe that if Northern Border uses these types of mitigation procedures, construction of the pipeline in the Dunn Center Alternate corridor should not result in any long-term degradation of the environment. With successful restoration measures, the impacts would be minor and short term. Accordingly, we will approve construction of the proposed facilities as modified by Northern Border in its initial brief, as described above.

VII.H. <u>Determination Of Pipeline Capacity</u>

Pursuant to Condition No. VI.1. on page 39 of the President's <u>Decision</u>, the determination of the sizing and capacity of the Northern Border pipeline is within the exclusive jurisdiction of the Secretary of Energy. The Secretary, in his letter of April 24, 1980 (at 4) has made the following determination:

> "...I hereby certify that there has not been a material change in the facts regarding future gas supplies for the East since the issuance of the President's <u>Decision</u> that would warrant certification of the Eastern Leg at a different rated capacity than authorized by the <u>Decision</u>. Therefore, the 42" pipe size authorization for the Eastern Leg in the <u>Decision</u> remains in effect."

We hereby incorporate the Secretary's determination, set forth above, as a condition to the project sponsors' certificate.

VIII. FINDINGS

The Commission additionally finds:

(1) The applications of Northwest Alaskan Pipeline Company, Docket Nos. CP78-123, et al. and CP79-170, Northern Border Pipeline Company, Docket No. CP78-124, Northern Natural Gas Company, Docket No. CP79-396, United Gas Pipline Company, Docket No. CP79-400, and Panhandle Eastern Pipeline Company, Docket No. CP79-403, are related to the overall construction and operation of the Alaskan Natural Gas Transportation System within the meaning of Section 9 of the Alaska Natural Gas Transportation Act to the extent that these applications are granted herein.

(2) The applicants Northern Natural Gas Company, United Gas Pipeline Company, and Panhandle Eastern Pipeline Company have been previously found by the Commission to be natural gas companies within the meaning of the Natural Gas Act.

(3) All previous authorizations issued to the original Northern Border partnership in prior Commission orders are transferred to the present Northern Border Pipeline Company, and the applicant, Northern Border Pipeline Company, upon commencement of the transportation services authorized herein will be engaged in the transportation of natural gas in interstate commerce, subject to the jurisdiction of the Federal Energy Regulatory Commission, and will be a "natural gas company" as defined in the Natural Gas Act.

(4) The applicant, Northwest Alaskan Pipeline Company, upon commencement of the sale for resale in interstate commerce herein authorized will be a "natural gas company" within the meaning of the Natural Gas Act when conditioned as discussed above.

(5) Grant of the import authorizations applied for in this docket will not be inconsistent with the public interest under Section 3 of the Natural Gas Act.

(6) The sale and or transportation and construction of facilities proposed by applicants in these proceedings will be in interstate commerce subject to the jurisdiction of the Commission, and therefore subject to the requirements of subsections (c) and (e) of Section 7 of the Natural Gas Act.

(7) The sale of natural gas proposed in the application of Northwest Alaskan Pipeline Company in Docket No. CP79-170 is required by the public convenience and necessity, and therefore a certificate as herewith ordered and conditioned should be issued.

(8) The construction and operation of the facilities proposed by Northern Border Pipeline Company in its application in Docket No. CP78-124 are required by the public convenience and necessity, and therefore a certificate as hereinafter ordered and conditioned should be issued.

(9) The transportation of natural gas proposed in the application of Northern Border Pipeline Company in Docket No. CP78-124 is required by the public convenience and necessity, and therefore a certificate as hereinafter ordered and conditioned should be issued.

(10) The construction and operation of the facilities proposed by Northern Natural Gas Company in its application in Docket No. CP79-396 are required by the public convenience and necessity, and therefore a certificate as hereinafter ordered and conditioned should be issued.

(11) The transportation/displacement and exchange agreements proposed by Northern Natural Gas Company in Docket No. CP79-396, by United Gas Pipeline Company in Docket No. CP79-400, and by Panhandle Eastern Pipeline Company in Docket No. CP79-403, are required by the public convenience and necessity, and therefore certificates as hereinafter ordered and conditioned should be issued.

(12) The application of ANB Gas Company in Docket No. CP79-399 has not been shown to be required by the public convenience and necessity, and it therefore will be denied.

(13) All applicants in this proceeding are able and willing to do the acts properly and to perform the service proposed and to conform to the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commission thereunder.

IX. ORDER

The Commission orders:

(A) Upon filing of an appropriate application for approval of border facilities pursuant to Executive Order 10485,

such application to be accepted by letter order issued by the Secretary at the direction of the Commission, Northwest Alaskan Pipeline Company, Docket No. CP78-123, et al., is authorized under Section 3 of the Natural Gas Act to import on an average daily basis up to 800,000 Mcf of gas at a point on the U.S. - Canada Boundary near Monchy, Saskatchewan, provided that said importation be on the terms and conditions of this order as hereinafter set forth:

(a) Applicant shall make, keep and preserve full and complete records with respect to the natural gas herein authorized to be imported and shall file with the Commission annual reports showing, by months, the quantities of gas imported during the preceding calendar year, together with the volumes imported on the peak day of each month, and such other reports with respect to such importation as the Commission may deem necessary and in such form and manner as the Commission may prescribe.

(b) The authorization herein granted shall not be transferable or assignable and shall remain in effect only so long as applicant continues the acts and operations herein authorized in accordance with the provisions of the Natural Gas Act and the requirements, rules and regulations of the Commision thereunder, and in accordance with the terms and conditions of this order.

(c) Applicant shall not, during the term of the authorization granted by this order, materially change or alter its import operations without first obtaining the permission and approval of the Commission.

(d) In the event that applicant should abandon or permanently cease for any reason whatsoever all or any part of the instant import operation, applicant shall forthwith notify the Commission of said fact and the reason therefor.

(e) Applicant shall comply with the requirements of Section 153.8 of the Commission's Regulations under the Natural Gas Act.

(B) A certificate of public convenience and necessity is issued to Northern Border Pipeline Company authorizing the the construction and operation of pipeline facilities, as described more fully in its application in Docket CP78-124, for the transportation in interstate commerce of up to 800,000 Mcf of gas per day for Northern Natural Gas Company, United Gas Pipeline Company and Panhandle Eastern Pipeline Company, upon the terms and conditions of this order.

(C) A certificate of public convenience and necessity is issued to Northwest Alaskan Pipeline Company in Docket No. CP79-170, authorizing the sale of a daily volume of 800,000 Mcf of natural gas to Northern Natural Gas Company, United Gas Pipeline Company and Panhandle Eastern Pipeline Company, as hereinbefore described and as more fully described in the application upon the terms and conditions of this order.

(D) A certificate of public convenience and necessity is issued to Northern Natural Gas Company in Docket No. CP79-396, authorizing the transportation/displacement and exchange arrangements with United Gas Pipeline Company and with Panhandle Eastern Pipeline Company, and the construction of facilities as more fully described in the application filed in said docket, upon the terms and conditions of this order.

(E) A certificate of public convenience and necessity is issued to United Gas Pipeline Company authorizing the transportation/displacement and exchange arrangements with Northern Natural Gas Company, as hereinbefore described and as more fully described in the application filed in Docket No. CP79-400, upon the terms and conditions of this order.

(F) A certificate of public convenience and necessity is issued to Panhandle Eastern Pipeline Company authorizing the transportation/displacement and exchange arrangements with Northern Natural Gas Company, as herein before described and as more fully described in the application filed in Docket No. CP79-403, upon the terms and conditions of this order.

(G) The tariffs, rate schedules, and service agreements to be filed shall be consistent with the determinations discussed in the body of this decision. Within thirty days after the commencement of construction of the Alaskan segment of the ANGTS, Northern Border Pipeline Company shall file appropriate revisions to its tariff to restate its depreciation rates to reflect inclusion of Alaskan gas.

(H) The application of ANB Gas Company in Docket No. CP79-399, as hereinbefore described and as more fully described in the application, is hereby denied.

(I) The certificates granted herein and the exercise of any rights thereunder are conditioned upon compliance by Northwest Alaskan Pipeline Company, Northern Border Pipeline Company, Northern Natural Gas Company, United Gas Pipeline Company, and Panhandle Eastern Pipeline Company, respectively, with all applicable regulations of the Commision under the Natural Gas Act.

(J) Northern Border Pipeline Company and Northen Natural Gas Company shall report promptly in writing and under oath the dates of commencement and completion of construction of facilities authorized herein and the date of commencement of service through such facilities. Such reports shall be filed with the Commission within 15 days after completion of construction, and after commencement of service, respectively, as authorized herein.

(K) A certificate issued herein shall be void unless the applicant to whom the certificate is issued accepts it in writing: (a) within 30 days of the expiration of the period specified for filing petitions for rehearing in ordering paragraph (M), or (b) within 30 days of the date of issuance of a Commission order on rehearing, or (c) within 30 days of the date a petition for rehearing is deemed denied in accordance with section 1.34 of the Commission's Rules of Practice and Procedure, whichever occurs later.

(L) The construction authorized herein shall be undertaken as provided by paragraph (b) of Section 157.20 of the Regulations under the Natural Gas Act, within one year from the date of this order.

(M) Parties to the above-captioned dockets may file petitions for rehearing of this order within 30 days of the date of issuance of this order. The petitions for rehearing shall be submitted pursuant to the procedures set forth in section 1.34 of the Commission's Rules of Practice and Procedure.

(N) This order shall not become effective until: (a) the expiration of the period for filing petitions for rehearing specified in ordering paragraph (M), or (b) until the date of issuance of a Commission order on rehearing, or (c) until the date when such petitions are deemed denied in accordance with section 1.34 of the Commission's Rules of Practice and Procedure, whichever occurs later.

By the Commission. Commissioner Holden, dissenting in part, filed a separate statement appended hereto.

(S E A L)

Kenneth F. Plumb

Kenneth F. Plumb,
Secretary.

THE SECRETARY OF ENERGY
WASHINGTON, D.C. 20585

April 24, 1980

Honorable Charles B. Curtis
Chairman
Federal Energy Regulatory Commission
Washington, D.C. 20426

Re: Alaska Natural Gas Transportation System -- Eastern Leg
Docket No. CP78-123, et al

Dear Mr. Chairman:

I would like to address several matters regarding the pre-build portions of the Eastern Leg of the Alaskan Natural Gas Transportation System (ANGTS). Petitions for certification of the United States section of the Eastern Leg pre-build are now before the Commission.

The ANGTS is a critical energy project for the United States. By completing ANGTS expeditiously, we can bring the enormous reserves of North Slope Alaskan natural gas, now estimated at over ten percent of all U.S. proven natural gas reserves, to our domestic markets in the lower 48 states.

As the Commission recognized in its Order on the pre-build portion of the Western Leg, pre-building in general will produce tangible benefits for the entire system.[1/] Prebuild will make for an earlier start for ANGTS. It will spread demand for labor, materials, and capital over several years, thereby reducing the costs and construction delays that might otherwise result from manpower and material shortages. In addition, transportation of Albertan gas through the pre-build portions will reduce the unit cost of service for the Alaskan gas. Finally, completion of the pre-build portions of the system by 1981 and their successful operation during the early 1980's will facilitate private financing of the remainder of the system.

1/ "Findings and Order Issuing Certificates of Public Convenience and Necessity and Authorizing the Importation of Natural Gas," Docket Nos. CP78-123 et al. (issued January 11, 1980) at 24-26.

The matter of certification of Eastern Leg pre-build is pending before the Commission. The Commission has recognized the sponsors' requirement for timely action in order that the sponsors can proceed with procurement and other commitments that will enable them to maintain their schedule of starting construction this year and placing the Eastern Leg in service during the fall of 1981. In this regard, the Department appreciates the Commission's pursuit of an April date for its final authorization decision. In light of the national importance of ANGTS and the contribution that pre-build can make to the entire system, I believe that it is in the public interest for the Commission to proceed with its final authorization decision this month in order to facilitate completion of the Eastern Leg on the current construction schedule.

In order to assist the Commission in its timely consideration of the Eastern Leg application, I would like to provide information on three issues. The first two issues, financing of the pipeline and marketability of the Canadian gas that will flow through it, will be important to the Commission's deliberations on certification. The third, pipe size, is an issue on which I am required to make a determination.

First, as to financing, as you approach this issue, I am sure you will have in mind the commitment of the governments of both the United States and Canada to facilitate the expeditious and efficient construction of the ANGTS as a privately financed venture.[2/] The Eastern Leg pre-build in itself is a major natural gas pipeline. The Eastern Leg sponsors have worked diligently and apparently successfully to assemble a private financing package that should provide sufficient funding to start Eastern Leg construction this summer and complete it in the fall of 1981. The sponsors' proposals for unit-of-throughput depreciation provisions, routing of at least the requested volumes of Canadian gas through the Eastern Leg, and rolled-in pricing are essential features of this financial package.

One proposed feature of the sponsors' Eastern Leg financial plan, the minimum take requirements ("take-and-pay" contract provisions), is of particular concern. The Combination of higher prices for Canadian gas and high percentage minimum take requirements obviously affects the price competitiveness of Canadian natural gas imports with alternative fuels in U.S. markets. While some minimum take requirements are necessary for financing the pipeline and associated

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2/ "Agreement between the United States of America and Canada on Principles applicable to a Northern Natural Gas Pipeline," appearing in Decision and Report to Congress on the Alaska Natural Gas Transportation System, Executive Office of the President, Energy and Policy Planning (September 1977) at 48 and 50.

production facilities, the sponsors' proposal that calls for a specified volume to be taken regardless of future price increases could create an unreasonably large artificial market for Canadian gas in this country.

When acting on the minimum take requirements, it is essential that the Commission consider the effect of such requirements on our policy that imports of Canadian gas continue to be competitive with alternative fuels in U.S. markets. Accordingly, I recommend that, while taking into account reasonable requirements for private financing of the Eastern Leg, the Commission place any conditions on the minimum take requirements that are necessary to ensure that the future operation of those contractual provisions does not unreasonably compromise this policy.

In light of the national importance of the ANGTS, the benefits of pre-build for the entire system, and our obligations to facilitate expeditious construction of a privately financed ANGTS, I urge the Commission to give its every favorable consideration to the private financial package that the sponsors have arranged to fund timely completion of Eastern Leg pre-build, subject to review of the minimum take requirement for future price competitiveness as noted above. This recommendation is based upon the desirability of avoiding numerous changes in the current financial plan that could be time consuming to make and, therefore, cause delays in completing the Eastern Leg beyond the currently scheduled fall 1981 in-service date.

A second matter of importance for the success of this project is the marketability of Canadian import gas. As suggested above, the Department of Energy is vitally interested in maintaining a competitive relationship between the price of imported natural gas and of alternative fuels.

In this regard, I want to advise the Commission that on March 24, 1980, I met with the Minister of Energy, Mines and Resources of the Government of Canada. As a result of that meeting, the Canadian Government agreed to institute a pricing approach that should improve the price predictability and market stability associated with Canadian natural gas imports. For the Commission's reference I enclose copies of the letters exchanged between the Minister and myself that set forth the Canadians' new pricing mechanism. While this mechanism does not absolutely guarantee a competitive relationship between Canadian gas prices and alternative fuel prices in the U.S. markets, it substantially increases the likelihood that such a result will occur, thus providing a basis for concluding that Eastern Leg pre-build gas will be marketable.

Finally, pursuant to Section 5.VI.1 of the President's Decision, I am required to certify to the Commission whether there has been any material change in the facts regarding future potential gas supplies for the Eastern Leg since the Decision was issued that would warrant certification for the Eastern Leg facilities at a different rated capacity than authorized by the Decision. 3/ The President's Decision authorized 42" diameter pipe for the Eastern Leg. 4/

I have considered potential gas supplies from both Alaska and Canada. The Alaskan reserves have not increased significantly since the President issued his Decision in 1977. The proven reserves in Alberta, however, have increased markedly. Still, based upon a recent decision of Canada's National Energy Board, 5/ it appears the authorized 42" pipe size will provide sufficient capacity for the Canadian gas that probably will be available for import during the next several years.

Another aspect of gas supply besides quantity is the timing of its availability. Assuming that certain Canadian decisions respecting Canadian gas availability and construction of the Canadian portion of the Eastern Leg are forthcoming, Canadian gas will be available at the U.S. border for transmission through the U.S. portions of the Eastern Leg by the fall of 1981. It is important to have the Eastern Leg completed by this time in order that the pipeline can move the Canadian natural gas as soon as that fuel becomes available for import. I have considered the Eastern Leg sponsors' construction schedule, and believe that the sponsors should be able to complete a 42" pipeline by the fall of 1981.

Based on these assessments of quantities and timing of gas available for import through the Eastern Leg, I hereby certify that there has not been a material change in the facts regarding future gas supplies for the East since the issuance of the President's Decision that would warrant certification of the Eastern Leg at a different rated capacity than authorized by the Decision. Therefore, the 42" pipe size authorization for the Eastern Leg in the Decision remains in effect.

3/ Decision and Report to Congress on the Alaska Natural Gas Transportation System, Executive Office of the President, Energy and Policy Planning (September 1977) at 39-40.

4/ Id. at 21.

5/ National Energy Board, Reasons for Decision, In the Matter of Applications under Part VI of the National Energy Board Act of Alberta and Southern Gas Co., Ltd., et al. (November 1979).

I hope that you will find the matters discussed in this letter helpful in the Commission's deliberations. I look forward to continuing our work on this vital energy project.

Sincerely,

Charles W. Duncan, Jr.

Enclosure

cc: All Parties
    Federal Inspector

THE SECRETARY OF ENERGY
WASHINGTON, D.C. 20585
March 26, 1980

The Honorable Marc Lalonde
Minister of Energy, Mines and Resources
Ottawa, Ontario K1A0E4
Canada

Dear Mr. Minister:

Your letter concerning Canada's new gas pricing policy is in accordance with my understanding of our discussions yesterday in Ottawa. Implementation of this system should substantially improve the price predictability and market stability associated with our importation of Canadian natural gas, particularly in terms of the competitive relationship between Canadian gas export prices and alternative fuel prices.

As I know you are aware, under U.S. law the importation of natural gas into the U.S. is subject to regulatory review and approval by the Economic Regulatory Administration and the Federal Energy Regulatory Commission. However, to the extent that the pricing mechanism which you described meets our regulatory requirements, as a matter of policy, I would support this mechanism for the pricing of Canadian natural gas.

Like you, I appreciated the opportunity for us to meet and discuss a broad range of energy issues. The progress we made was important, and I look forward to a frequent continuation of this dialogue.

Sincerely,

CW Duncan Jr.

March 25, 1980

Dear Mr. Duncan,

I have pleasure in enclosing the Statement of Principles on Canadian gas export pricing which we discussed at our March 24 meeting in Ottawa.

I understand from our conversations that the application of these principles is acceptable to you as a method of adjusting the price of our natural gas exports, commencing April 1, 1980.

Should implementation of this method result in export-price increases occurring in two consecutive months or more than twice in any six-month period, I would readily agree to discussion between our respective officials in the context of the Canada-United States energy consultative mechanism.

I would certainly hope that the understanding we have reached on this important matter will lead to the expeditious and favourable regulatory treatment of current and future applications for the import of Canadian gas to the United States.

I am pleased that our first meeting was a productive one and I am looking forward to continuing an effective working relationship with you.

Yours sincerely,

Marc Lalonde

The Honourable
Charles W. Duncan, Jr.,
Secretary of Energy,
WASHINGTON, D.C.

STATEMENT OF PRINCPLES ON CANADIAN GAS EXPORT PRICING

1. The export price shall be calculated according to the following substitution value formula:

   A) F.O.B. price of Canadian oil imports, as measured by the Petroleum Compensation Board in U.S. dollars per barrel, divided by 5.796 to convert to U.S. dollars per MMBTU.

   Less

   B) An adjustment factor which shall be determined from time to time by the Governor in Council. The adjustment factor shall not be less than U.S. $0.22, which is the transportation adjustment implicit in the existing U.S. $4.47 border price. (See Annex 1)

   Plus

   C) The weighted average transportation cost of export gas as determined by the National Energy Board. (See Annex 2)

   Equals

   D) The export price at the international border (see Annex 2 for a sample calculation).

2. The export price shall be measured monthly. If the substition value calculation indicates a change in the export price of less than U.S. $0.15, the export price shall not be changed. If the substitution value indicates a change in the export price greater than U.S. $0.15 the export price shall be changed in the following way:

   A) The United States would be notified of the change before the 15th of the month.

   B) The change shall become effective 90 days after the measurement date (i.e. 75 days after the notification date).

3. The process in (2) above shall commence 1 April 1980, the effective date of the first export price change would thus be July 1, 1980. The adjustment factor for the April measurement shall be U.S. $0.22.

[illegible]

DERIVATION OF THE ADJUSTMENT FACTOR

	DLRS US/BBL	DLRS US/MMBTU
Ocean Freight	1.15	
Ocean Loss	.16	
Pipeline Toll (Portland to Montreal)	.40	
Pipeline Toll (Montreal to Toronto)	.14	
Equals:		
Oil transportation charge to Toronto	1.85	
Less:		
Gas Transportation charge, Toronto to Alberta border		
Equals:		
Adjustment Factor		

ANNEX I

SUBSTITUTION VALUE CALCULATION, 1 JANUARY 1980

		DLRS US/BBL	DLRS US/MMBTU
1.	F.O.B. Oil Price	26.24	4.53
Less			
2.	Adjustment Factor		.22
Plus			
3.	Average Transportation Cost to U.S. Border		.16
Equals			
4.	Export Price		4.47

Northwest Alaskan Pipeline Company *et al*.) Docket No. CP78-123, *et al*.

HOLDEN, Commissioner, dissenting (in part):

This is the first official action regarding the Alaskan Natural Gas Transportation System on which the Commission has not been unanimous as to the final result. 1/

The proposed system of which this "pre-build" segment is necessarily a part has been given high priority as national policy. It has been much too long delayed. The chief reasons have not to do with regulation but with underlying obstacles to the presentation of a financing plan. 2/ Precisely because the overall project is so important, and this pre-build segment is necessarily a part of that overall project, I would make clear that my difference of opinion is as to a matter of judgment.

The matter of judgment concerns a rate-design issue only. I dissent from the portion of the order that addresses the manner in which the shippers must classify Northern Border charges in passing those charges on to their customers. The majority has chosen to require shippers to track all Northern Border charges in the demand component of each shipper's rates.

1/ There might have been other approaches than those taken on certain prior questions relating to the overall system, notably design (see my concurrence to "Order Denying Petitions to Vacate Order on Alaskan Segment Specifications and Initial System Capacity," issued in this docket October 19, 1979). But those matters have been judicially resolved in Earth Resources Company of Alaska v. FERC, No. 79-2191, (D.C. Cir., January 3, 1980) and are now well behind us.

2/ Ultimately it is the presentation and effectuation of a financing plan for the overall system that will determine the future of that system. This present order concerns the "pre-build" project which now emerges as such a vital contribution to the ultimate achievement of that system. As to the resolution of the issues with respect to financing of the overall system, the catalytic roles lie elsewhere in the Government and/or the private sector. Indeed, as Commisssioner, I have no official basis of knowledge as to what those major impediments are or what the means of their resolution would be, except that they clearly have not been presented in a format suitable to the regulatory process.

The rate design process involves three general steps.

(1) Costs are classified as fixed or variable costs, and then further classified into demand or commodity categories.

(2) Once costs are placed in the demand or commodity category they are allocated among the jurisdictional and nonjurisdictional customers of the interstate pipeline. Costs assigned to the demand category are allocated among jurisdictional and nonjurisdictional services on the basis of peak usage, e.g. the average consecutive three-day peak volumes; whereas costs assigned to the commodity category are allocated on the basis of sustained usage, e.g. annual volumes in the case of transmission costs and heating season volumes in the case of storage costs.

Generally, the portion of peak period sales made to jurisdictional customers is higher than the portion of annual or heating season sales made to jurisdictional customers. As a result, any classification of costs which places a greater portion of total costs in the demand category generally results in a greater apportionment of total costs to jurisditional customers.

(3) After allocating costs between jurisdictional and nonjurisdictional services, the next step is to apportion the costs which were allocated to jurisdictional services among the jurisdictional customers. This is usually accomplished through rate design by dividing costs between the demand charge and commodity charge paid by each customer. Customers pay a demand charge based on their contractual right to purchase a certain volume of gas, and a commodity charge based on the actual units purchased.

The word "demand" serves two different functions in the rate design process. The majority only focuses upon the first stage in the process, where costs are classified as fixed or variable, and the third stage of the process, where the word "demand" is used to describe a fixed monthly or annual charge which a customer is obligated to pay. Yet the word "demand" takes on a quite different meaning in the middle stages of the rate design process when all costs assigned to the "demand" category are allocated among groups of customers, jurisdictional and nonjurisdictional, on the basis of peak day usage. There are many important policy issues involved in this middle stage. By focusing only upon the beginning and the end of the process the majority pays less attention than I would to the policy issues inherent in assigning charges to the demand component.

The present order opts for classifying all of Northern Border's charges to the shippers as demand charges on the basis that they "behave" like demand charges. That is, because most of Northern Border's charges consist of fixed costs, and because the shipper's obligation to pay Northern Border will be based on a contractual amount of capacity, the charges look like a demand charge in a two part rate.

However, simply because Northern Border's charges are virtually 100 percent fixed does not mean that they are the equivalent of a demand charge. It has not been the practice of the Commission to classify certain costs to the demand category just because the costs are fixed. To the contrary, a large portion of fixed costs (usually 75%) are assigned to the commodity category. The majority's analysis misses that important characteristic of the cost classification process.

It is not necessary to classify Northern Border's charges to the shippers in order to meet Northern Border's needs. Northern Border's costs-of-service tariff provides a means for recovering all of its costs from the shippers without the need to classify the charges in any particular manner or to allocate costs among the various shippers -- the customers of Northern Border. The need to classify Northern Border charges only arises when the shippers seek to pass on those costs to their customers. The customers of shippers are the ones who will bear the brunt of Northern the Border's costs. It is the impact upon those customers which should be the focus of attention in making the policy choices inherent in a classification decision. For this reason I would make no classification of Northern Border charges until those charges appear in the rates of the shippers to be passed on to their customers. The time and place to make that choice is when the rate structure of each shipper is before the Commission for decision. Until then the shippers should use the method they currently use for classifying and allocating other costs among their customers.

The majority decides that Northern Border's charges must be classified at the time they are paid by the shippers because it first decides that the shippers should pass on those charges classified in the same manner "as-billed" to them. In order for shippers to pass on charges "as-billed," the charges must be classified when billed to the shippers. Thus, the majority decides it must classify Northern Border charges. This seems to put the cart before the horse. The "as-billed" policy simply does not apply in the context advanced by the majority.

The "as-billed" policy, 3/ as the majority points out, operates to prevent a reclassification of costs once an initial judgment has been made as to how certain costs by the provider of a service or sale should be classified. The policy applies primarily to third-party transportation costs. First a judgment is made as to how costs should fall upon various groups of customers, through the appointment of costs between the demand and commodity categories in the rates of the first transporting pipeline. That apportionment remains the same as the costs are passed on down stream to the ultimate beneficiaries because the "as-billed" policy prevents a reclassification and shifting of costs among groups of customers at each pipeline level. This policy effectively views the facilities of the provider of the service as an extension of the system of the receiver of the service.

The "as-billed" policy serves as a means. It is not itself an end. In order for the policy to apply at all there must have been an initial choice as to how costs should fall on various customers, an allocation to which the policy could be applied to preserve. Yet the majority first decides that a particular means to preserve a goal should be employed -the "as-billed" policy -- and then decides the goal -- classification of all Northern Border costs in the demand category. The majority does not even argue, as it plausibly might, that its procedure is justified because the ANGTS is *sui generis*, an argument strongly made in prior orders. Thus, it may appear to have spoken too broadly on rate design.

I would, instead leave the classification policy issues to be resolved within the rate structure of each shipper. After all, the whole point of the cost classification portion of this order is to determine how the *shippers* will recover Northern Border charges, and not how *Northern Border* will recover its costs from the shippers. Order No. 31 fully addressed Northern Border's recovery of costs from the shippers. It need not be revisited here, especially without prior notice and opportunity for the affected parties to make their positions known.

3/ This policy is described in *United Gas Pipeline Company*, Docket No. RP77-107, order issued July 30, 1979, at p. 10-11. Contrary to indications of the majority, this is not the same *United* formulation connected with the 25/75 classification of fixed costs discussed in Opinion No. 21.

The end result of what the majority does is to allocate Northern Border costs among the shippers' customers on the basis of each customer's use of the shipper's facilities on peak-days. This places most of the burden on jurisdictional customers because of the peculiarity of the way in which costs are allocated in the shippers' rates. Thus, as to this rate design aspect if the order I respectfully dissent; but concur as to all others.

Matthew Holden, Jr.

Matthew Holden, Jr.
Commissioner