

93 HRS PERC, ORDER SETTING VALUES

FERC - ORDER  
SETTING VALUES  
FOR INCENTIVE  
RATE OF RETURN

UNITED STATES OF AMERICA  
FEDERAL ENERGY REGULATORY COMMISSION

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Before Commissioners: Charles B. Curtis, Chairman;  
Don S. Smith, Georgiana Sheldon,  
and George R. Hall

Determination of Incentive )  
Rate of Return, Tariff, ) Docket No. RM78-12  
and Related Issues )

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)

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I. INTRODUCTION

By this Order, the Federal Energy Regulatory Commission (Commission) resolves three complex and interrelated issues concerning the segments 1/ of the Alaska Natural Gas Transportation System (ANGTS) located in the United States: (1) the structure of the initial tariffs to be applied to the transportation of Alaskan gas; (2) the Incentive Rate of Return (IROR) mechanism and the values to be applied to

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1/ These segments are on the Alaskan segment and the Eastern leg (Northern Border). The only tariffs currently before the Commission for approval are those filed by Alaskan Northwest Natural Gas Transportation Company on behalf of the Alaskan segment, and by Northern Border Pipeline Company on behalf of the Northern Border segment.

the separate elements of that mechanism; and (3) the rate of return on equity to be applied once the system becomes operational.

A. Scope of Order

This Order is divided into six major sections. Section II is concerned with the Incentive Rate of Return, its rationale and mechanism. The four parts to this section explore and define the incentive concept (Part A), the six IROR parameters (Part B), and the implementation of the incentive mechanism (Part C). Sections III and IV deal with particular adjusting mechanisms which are required for the proper implementation of the Incentive Rate of Return. These are the Adjustments for Inflation (Section III) and Change in Scope mechanisms and procedures (Section IV). Section V provides a general overview of the result of the IROR mechanism. Taken together, these four sections supplement the basic framework for an incentive mechanism, specified in Commission Order No. 17, 2/ which is designed

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2/ Federal Energy Regulatory Commission, Order No. 17, "Order Attaching Incentive Rate of Return Conditions to Certificates of Public Convenience and Necessity, Docket No. RM78-12 (Dec. 1, 1978) confirmed, Order No. 17-A (Jan. 12, 1979).

to reward project sponsors for good management and effective control of costs.

The project sponsors' proposed tariffs are addressed in Section VI. The focus of that section is to resolve important issues which affect the risk to be borne by project sponsors in the construction and initial operation of the ANGTS. The relationship between the tariff issues and the IROR mechanism is important.

The last section (Section VII) addresses two procedural issues. These concern the use of the rulemaking process, and the relationship of this rulemaking to other pending proceedings pertinent to certification of the ANGTS. 3/

The resolution of tariff, incentive rate, and rate of return on equity issues for the Alaskan Northwest and Northern Border segments of the ANGTS are embodied in the text of this Order, and implemented through the ordering paragraphs and the terms and conditions.

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3/ These proceedings focus upon issues surrounding the building of natural gas facilities which, prior to transporting gas as a part of the ANGTS, will be used to transport Canadian gas. See Northwest Alaskan Pipeline Company, Docket Nos. CP78-123, et al., "Order Consolidating Proceedings, Establishing Procedures, Granting Interventions and Initiating Hearings." (April 20, 1979.)

The project sponsors have earnestly sought that this Order, especially as it relates to the tariff structure, provide assurance to prospective equity investors and lenders. The concern of the sponsors is wellfounded. The Commission fully recognizes that equity investors and lenders will make critical decisions respecting the financing of construction of the ANGTS in reliance on this Order.

The Commission has articulated in great detail its rationale for this Order. Where reasoned alternatives were available, we have provided a thorough analysis of the issues and the basis for our conclusions. This thoroughness provides the investors' best security in relying on this Order.

B. Background

The Prudhoe Bay Field, on the north slope of Alaska, contains the largest single gas reservoir ever discovered on the North American continent. Virtually every estimate exceeds 26 trillion cubic feet of proven, recoverable natural gas reserves. This large deposit of natural gas could supply more than two billion cubic feet of natural gas per day (approximately five percent of the nation's current gas requirements) over a 25-year period.

In recognition of the potential importance of this domestic energy source, Congress passed the Alaska Natural Gas Transportation Act (ANGTA), Pub. L. No. 94-586, 90 Stat. 2903 (1976) (15 U.S.C. §§ 719-719m), which authorized the President to recommend a natural gas system to transport Alaskan natural gas to the contiguous lower-48 States. In September of 1977, the President rendered a decision that the Alcan Pipeline Company, because its proposal was environmentally and economically superior to competing proposals, should be granted the certificate to construct the ANGTS. 4/ Congress, by joint resolution, approved and adopted the President's selection in November of that year, H.J. Res. 621, Pub. L. No. 95-158, 91 Stat. 1268 (1977).

The ANGTS will be 4,800 miles in length, originating on the north slope of Alaska and passing through Canada to the

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4/ Executive Office of the President, Energy Policy and Planning, Decision and Report to Congress on the Alaska Natural Gas Transportation System (September 1977) [hereinafter cited as Decision]. The present sponsors for the Alaskan segment are the successors to the Alcan Pipeline Company; see, Northwest Alaskan Pipeline Company, Docket Nos. CP78-123, et al., "Order Transferring Conditional Certificate of Public Convenience and Necessity from Alcan Pipeline Company to Alaskan Northwest Natural Gas Transportation Company, Reviewing Relevant Portions of Underlying Partnership Agreement and Granting Intervention," (June 30, 1978). The sponsor for the Eastern Leg Segment is the Northern Border Pipeline Company.

lower-48 states. 5/ This system is expected to deliver about 2.4 billion cubic feet of natural gas per day to markets in the lower-48 States. At the time of the President's Decision the capital costs were estimated at \$10.5 to \$13.9 billion 6/, which would make the project the largest privately financed project in history. 7/

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5/ The ANGTS will be a chilled, buried, natural gas pipeline that will run parallel to the Trans-Alaska Oil Pipeline, to Delta Junction, just south of Fairbanks. From there, it will run parallel to the existing Alcan Highway through southern Alaska and northwestern Canada to Caroline Junction, near Calgary, Alberta. (In addition to transporting Alaskan gas, this section may also carry Canadian gas from the Mackenzie Delta region to the Trans-Canada Pipeline at Empress, Alberta.) At Caroline Junction, the system will divide into two legs: the Eastern Leg (Northern Border pipeline in the United States), which will carry approximately two-thirds of the gas eastward to a point near Chicago, and the Western Leg, which will parallel an existing Pacific Gas Transmission Company pipeline, carrying the remaining one-third from Alberta to California. See Decision at 6-12.

The pipeline system in the U.S. will be built by three major pipeline companies. The Alaska segment, from Prudhoe Bay to the Yukon Border, will be constructed by the Alaskan Northwest Natural Gas Transportation Company. The Western Leg will be built by the Pacific Gas Transmission Company. The Northern Border segment will be built by the Northern Border Pipeline Company.

6/ Decision at 157.

7/ The sponsors state they are unable to provide current cost estimates, which have increased since 1977,

(Footnote continue on next page).

In the course of deciding the issues presented in this Order, the Commission has reviewed an extensive record compiled over the past several years in numerous proceedings. This includes the record developed prior to the President's Decision during the lengthy Alaska natural gas hearing in which the Commission first considered project alternatives, 8/ and the Recommendation submitted by the Federal Power

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7/ (Footnote cont'd.)

reflecting inflation and changes in original cost estimates as well as changes in project design. Letter of Mr. Rush Moody, Jr., Counsel representing Alaskan Northwest and Northern Border, to Mr. John B. Adger, Jr., Director, Alaskan Gas Project Office, Federal Energy Regulatory Commission (May 3, 1977).

8/ See, El Paso Alaska Company, Docket Nos. CP75-96, et al., Initial Decision on Proposed Alaska Natural Gas Transportation Systems (Feb. 1, 1977).

On October 1, 1977, pursuant to the provisions of the Department of Energy Organization Act (DOE Act), Pub. L. No. 95-91, 91 Stat. 565 (August 4, 1977), and Executive Order No. 12009, 42 Fed. Reg. 46267 (Sept. 15, 1977), the Federal Power Commission ceased to exist and its functions and regulatory responsibilities were transferred to the Secretary of Energy and this Commission, which, as an independent commission within the Department of Energy, was activated on October 1, 1977. The Commission was assigned all relevant authority not granted to it under the DOE Act respecting action concerning the ANGTS. Department of Energy Delegation Order No. 0204-8 (effective Oct. 1, 1977) 42 Fed. Reg. 61491 (Dec. 5, 1977).

Commission to the President prior to the President's Decision. 9/ In addition, there is the record of comments submitted to the President on the Commission's Recommendation, comments on the President's Decision submitted by this Commission and others to the Congress, and the hearings held by Congress pursuant to approving the Decision. Finally, there is the extensive record compiled in this rulemaking, a record which consists of comment submitted to the Commission during the proceedings initiated on May 8, 1977, 10/ six studies or reports dealing with IRGR issues, 11/ a special tariff report of the Commission's Alaska Delegate, and comments and reply comments submitted to the Commission pursuant to the April 6, 1979 Notice.

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9/ FPC, Recommendation to the President, Alaska Natural Gas Transportation Systems (May 1, 1977) [hereinafter cited as Recommendation].

10/ Federal Energy Regulatory Commission, "Incentive Rate of Return from the Alaska Natural Gas Transportation System" Notice of Proposed Rulemaking, Docket No. RM78-12 (May 8, 1978), 43 Fed. Reg. 20245 (May 11, 1978), revised Sept. 15, 1978.

11/ The reports received were: Alaska Gas Project Office FERC, "Price Indices for Adjusting the Cost Performance Ratio of the Alaska Gas Pipeline: Analysis and Recommendations" (March 29, 1979)[hereinafter cited as Alaska

(Footnote continue on next page).

The Decision was the final product of a process, stipulated by Congress in ANGTA, 12/ that included written comments from Federal officers and agencies, as well as State governors, and certain separate evaluations by the council of Environmental Quality. These comments and reports covered matters such as environmental

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11/ (Footnote cont'd.)

Gas Project Office Report]; J. Hass, "Risk, Return and the IROR Plan: A Report to the Federal Energy Regulatory Commission" (March 1979) [hereinafter cited as Hass Report]; James D. McCullough, Institute for Defense Analysis, "On the Treatment of Risk, and Uncertainty in Determining Change in Scope Allowability and Center Point Establishment in the Alaska Gas Pipeline IROR Mechanism" (March 1979) [hereinafter cited as McCullough Report]; Northwest Alaskan Pipeline Company, "Allowable Cost Estimate Revisions Under the Incentive Rate of Return Procedure (March 3, 1979) [hereinafter cited as Northwest Alaskan, Allowable Cost Estimate Revisions"]; Northwest Alaskan Pipeline Company, "Determining the Project Risk Premium for the Alaska Segment of the Alaska Natural Gas Transportation System" (March 7, 1979) [hereinafter cited as Northwest Alaskan, "Determining Project Risk Premium"]; Northwest Alaskan Pipeline Company, "Recommended Inflation Adjustment Under the Incentive Rate of Return (IROR) Procedure" (March 7, 1979) [hereinafter cited as Northwest Alaska "Recommended Inflation Adjustment"]. All of these reports were served on interested parties of record. See Federal Energy Regulatory Commission, "Determination of Incentive Rate of Return, Tariff and Related Issues For The Alaska Natural Gas Transportation System," Docket No. RM78-12 at 18 n. 24 (mimeo) (April 6, 1979) [hereinafter the April 6 Notice].

12/ ANGTA, Section 6 (15 U.S.C. §719d).

and safety considerations, financing, and the relationship of any decision on the ANGTS to other aspects of national energy policy. These submissions formed an important part of the record from which the President's Decision, with all of its attendant terms and conditions, was developed.

The FPC's Recommendation found that the net national economic benefit (NNEB) was large and positive for any of the three alternatives which the Commission had considered, and it recommended that one of the two overland routes be constructed. 13/ However, several of the July 1, 1977, reports to the President explored the impact of higher-than-anticipated costs on the benefits of the proposed projects. In particular, task forces studying construction delay and cost overruns on the one hand, 14/ and national economic impact on the other, 15/ combined

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13/ Recommendation, Chapter IV. NNEB is defined as "the present value of the benefits derived less the present value of resources employed in undertaking the project." Decision at 174.

14/ Department of the Interior and Department of Transportation, "Alaska Natural Gas Transportation System: White House Task Force Lead Agency Report on Construction Delay and Cost Overruns," (July 1977).

15/ Federal Energy Administration, Department of Commerce, Department of the Interior, Department of Labor, "Working Group: National Economic Impact of Alaskan Natural Gas Transportation Systems," (June 30, 1977).

forces in preparing an evaluation of the effects of cost overrun and schedule delay on NNEB. 16/

The President's Decision responded to the possibility of overruns in two ways. First, an analysis of the potential for cost overruns and time delay for

16/ This table is included to illustrate the genesis of the President's concern over the impact of cost overruns on the project's NNEB as evaluated at the time of the Decision:

Effect on NNEB of Expected Cost  
Overrun and Worst Case Overrun  
(Billions of 1975 Dollars)

	<u>Discount Rate</u>		
Arctic			
Expected Overrun	10.4	3.3	0.9
Worst Case	2.6	-2.2	-3.4
Alcan			
Expected Overrun	12.3	4.8	2.0
Worst Case	6.6	0.7	-1.1
El Paso			
Expected Overrun	10.4	3.9	1.5
Worst Case	7.6	1.8	-0.1

Source: Federal Energy Administration, Department of Commerce, Department of the Interior--U.S. Geological Survey, Department of Transportation, Department of Treasury, Energy Research and Development Administration, "Report of the Working Group on Supply, Demand and Energy Policy Impacts of Alaska Gas." Table II-13, at 138 (July 1, 1977).

the selected project, as well as discussion of comparisons with the oil pipeline experience, was incorporated in the Report which accompanied the Decision. 17/ From that evaluation came an estimate of cost overruns under expected conditions, or an "expected overrun."

Second was the explicit recognition of the risk that cost overruns could be much different than the President's expected case, and the requirement that a framework be devised to minimize that risk. The framework, provided in the President's Decision, calls for the allocation of the project's risks among its various beneficiaries, and the organization of Federal Government interactions with the project to reduce those risks. 18/

The structure of government involvement includes a series of approvals designed to ensure that appropriate planning and analysis has been completed prior to construction,

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17/ The Report, following page 84 of the Decision, accompanied the Decision to Congress and may be regarded as authoritative legislative history. Midwest Gas Transmission Co. v. PERC, 589 F.2d 603, 611 n.23 (D.C. Cir. 1978).

18/ Decision at 201-205.

and an organization of the government's enforcement responsibilities in a manner which will provide coordinated and efficient action. 19/ It is this framework in its entirety -- reduction of risks as much as possible through appropriate government involvement, and allocation of residual project risks among the project's various beneficiaries -- that will provide the greatest likelihood of obtaining the expected positive benefits of the project.

The President's Decision places a number of requirements on the Commission to implement the framework within which the project is to proceed. One of the most important is to establish a variable or incentive rate of return mechanism to relate the allowed rate of return for equity for this project to the actual capital cost as compared with projected cost. 20/

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19/ Reorganization Plan No. 1 of 1979, submitted by the President to the Congress on April 2, 1979 pursuant to the provisions of 5 USCA §901 et seq.

20/ In the words of the Decision, the Commission was to fix "a variable rate of return on equity that will reward the applicant for project completion under budgeted cost and penalize the applicant for project completion above budgeted cost. The variable return shall be set to provide substantial incentive to construct the project without incurring overruns . . ." Decision at 36.

The consideration of the incentive rate of return mechanism and the project company tariffs will further assign appropriate risks to the project sponsors, and will establish the share of the cost overrun risk to be borne by gas consumers. The principal matters which remain for Commission consideration are consideration of the shipper company tariffs (including pass-through of charges under the tariffs approved herein), 21/ and the costs of processing and conditioning the gas for pipeline entry. The latter of these two matters is the subject of a rulemaking proceeding currently pending before the Commission in Docket No. RM79-19. 22/

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21/ The shipper companies have not yet filed their tariffs with the Commission.

22/ Before the Section 7 certification process for the ANGTS facilities is complete, the Commission must also approve (1) the certification cost and schedule estimates, and (2) the financing plans for the project's segments. Procedures for submission and consideration of certification costs and schedule estimates are being completed by the Commission's Alaska Delegate. These estimates could be filed now for the Northern Border and Western Leg segments of the ANGTS. For the Alaskan segment, these estimates must await the resolution of questions as to the maximum allowable operating pressure of that segment, and the proximity of that segment to the existing oil pipeline.

(Footnote continued on next page)

The final or ultimate cost of this project is now unknown; the best that can be done is to specify a probability distribution of possible final cost outcomes. The range of possible costs for a pipeline such as Northern Border is probably very narrow, whereas the range for the Alaska segment, with its inherent uncertainties regarding system design and logistics of construction, is likely to be much broader.

Cost estimates for most large projects tend to increase as more is known about the detailed design of the system. The classic example in this respect is the

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22/ (Footnote cont'd.)

The Commission has noticed for comment (in Northwest Pipeline Co., Docket No. CP78-123, et al.) a report on system design issues (pipe diameter and operating pressure), and the Department of the Interior has expressed its intention to resolve, in the near future, at least provisionally, the proximity question. Financing plans for the "pre-built" portions of Northern Border and Western Leg (i.e., southern segments to be built in advance of the Alaska segment, to transport gas from Canada pending completion of the full system) are presently being considered in a proceeding before the Commission in Northwest Alaskan Pipeline Co., Docket No. CP78-123, et al. Other financing plans will be considered as they are filed.

Trans-Alaska Oil Pipeline System (TAPS). The General Accounting Office (GAO) reports that, from an initial estimate of just over \$1 billion at the time it was first planned in 1968, the cost estimates had risen to over \$4 billion by May 1974 largely due to more detailed system definition and design, additions to the system size and sophistication, delay costs, and route and design changes. By the time the base control budget was established in early 1975, the cost estimates had grown to over \$6 billion. <sup>23/</sup> The GAO reports that this tendency is not restricted to the oil pipeline, but is a common feature in other large projects. <sup>24/</sup>

As discussed in considerably more detail in Section II.B.2 (the Center Point), the President's Decision took this tendency into account by allowing for expected overruns from the March 1977 estimates. Further review by the Commission suggests that 1.3 times the March 1977 estimate is a reasonable allow-

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<sup>23/</sup> Comptroller General of the U.S., Report to the Congress: Lessons Learned From Constructing the Trans-Alaska Oil Pipeline at 10 (June 15, 1978).

<sup>24/</sup> Id. at 19-20.

ance for cost growth after this estimate is corrected for inflation and scope changes. However, as Alaskan Northwest points out, the estimate might well be expected to grow as more is known about the detailed requirements for the project's design.

The Commission's problem is to be fair to the project sponsors, given the realities of the cost estimation process, while protecting gas consumers from being exposed to an uneconomic project. The Commission's approach has been to structure the IROR mechanism to accommodate changes in cost estimates attributable to increasing knowledge of design requirements, through adoption of a liberal design change policy prior to the commencement of construction. However, the Commission insists that realistic cost estimates be provided to the government prior to the commencement of construction. This result is achieved by severely constraining the circumstances in which scope changes will be considered once construction has commenced.

The Commission views the IROR mechanism as one of a number of policy tools that the Federal government will use to ensure that the construction of the ANGTS continues to be in the public interest. The Commission

believes that the EROR mechanism it has developed can legitimately be expected to achieve the following objectives:

- o the development of the best possible cost estimates prior to commencement of construction; and
- o the provision of a workable incentive to construct the ANGTS within the parameters provided by approvals or authorizations which may be granted by the Commission and the Federal Inspector.

The President and the Congress found that adequate assurance of continued project viability, and appropriate completion guarantees from the project's direct beneficiaries, should allow the project to be financed in the private market. The Commission recognizes that, in order to achieve a privately financed project, debt service must be assured in all events once the system is complete. The Commission also recognizes that such assurance requires the approval of appropriate project company pro forma tariff provisions and service agreements, as well as assurance that the shippers who sign the service agreements can pass charges incurred under them through to their customers. The Commission observes that the parties are essentially unanimous in agreeing that assurance of pass-through is necessary.

However, certain mechanical and timing aspects of pass-through, as well as appropriate provisions for pass-through of charges incurred in Canada, of necessity are reserved for future proceedings when all tariffs are before the Commission.

The Commission recognizes the essential role of the project company tariffs with all of their attendant conditions in securing financing for the project. In its comments on the President's Decision, the Commission recognized that the Decision and the Agreement on Principles with Canada <sup>25/</sup> anticipated that these will be cost-of-service tariffs, as opposed to a stated rate, to ensure that revenues available to the project companies are adequate to meet their expenses irrespective of fluctuations in throughput volume or costs. We recognize that funds are to be advanced in reliance upon the regulatory approvals provided in this Order.

The size and potential importance of the ANGTS to U.S. energy supplies has led it to receive special

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<sup>25/</sup> The Decision incorporated an "Agreement on Principles" between the United States and Canada. Agreement on Principles Applicable to a Northern Natural Gas Pipeline, Decision, Section 7 at 47-83 (Sept. 20, 1977).

regulatory attention and priority. 26/ The Commission has created special administrative arrangements to expedite regulatory decisions and to assure that all necessary administrative resources are devoted to the analysis and resolution of matters in controversy. The Commission reaffirms its commitment to carry out its responsibilities under the President's Decision and ANGTA, as well as its general statutory responsibilities under the Natural Gas Act and the Natural Gas Policy Act as they pertain to this project, with maximum dispatch and full cognizance of the significance of this project for consumers and the nation as a whole. We believe we have provided in this Order the opportunity for the system equity capital suppliers to earn truly generous rates of return if they perform, and for U.S. energy users to obtain valuable natural gas supplies at a reasonable cost.

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26/ Both the President and Congress have singled out the ANGTS for special treatment. The most obvious instance is the special legislation incorporated in ANGTA and Congressional approval of the Decision; see also the provisions of Title I of the Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3550 (1978). The Department of Energy, National Energy Plan II (May 7, 1979) designates it as the top priority among potential supplemental sources of natural gas.

II. THE IROR MECHANISMA. Concept and Structure1. Concept

The President's Decision requires the use of a "variable" or incentive rate of return to deter cost growth during construction. 27/ The concept expressed in the President's Decision is straightforward: in order to provide an incentive for management to reduce costs, rates of return on equity should be increased if the actual construction costs of the project are controlled so as to be at or below the target estimates. In creating the incentive, the President sought to offer the project sponsors a positive reward for superior cost and schedule control, in a format that is not available under conventional public utility ratemaking practices. 28/

The traditional tool for cost control in natural gas pipeline construction has been regulatory oversight, with its attendant threat to disallow investments imprudently incurred during construction. Under traditional regulation,

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27/ Decision at 36.

28/ The Commission recognizes that additional incentives to control the cost of gas delivered by this project are created by the sponsors' interest in ensuring marketability for the delivered gas and by the need to stay within the pool of funds committed by investors for construction.

before any costs may be disallowed for inclusion in rate base they must be shown to have been imprudently incurred. This approach, resting on hindsight, implies that only those costs attributable to patently unreasonable management action may be disallowed.

In competitive industries the rate of return on equity is usually related to cost control. The IROR attempts to establish the same rate-control relationship in a regulated situation. To reach this goal, the Commission has made use of the following principles in designing the IROR:

- o the IROR should provide incentives to reward cost control performance and avoid or minimize cost overruns;
- o the IROR should provide just and reasonable compensation for investors so that sufficient capital may be attracted to finance the project; and
- o the cost to consumers should be lower where cost overruns have been minimized and investors have received an incentive return.

To facilitate future regulation of the project, the IROR will be implemented by an equivalent one-time adjustment to the equity portion of the project's capital costs instead of varying the allowed rate of return on equity. 29/

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29/ As explained more fully below, Section II.C., the adjustment is calculated from the discounted present value of the sums of return on equity and return of equity when the appropriate value from the IROR schedule is applied to the equity component of capital cost.

The IROR, then, is designed to complement the disallowance-of-cost mechanism by offering economic rewards for holding down costs. In addition to the standard process of allowing or disallowing costs according to the prudently-incurred standard, project managers will be rewarded for eliminating avoidable costs even though those costs (had they been incurred) might later withstand an allegation that they were not "prudent."

The consumer should be the chief beneficiary of the IROR. Under conventional regulatory practice, consumers may be forced to bear all cost overruns. Consumers traditionally bear not only the return and taxes associated with the additional capital necessary to finance the overruns, but also the depreciation expense associated with the return of that investment. Using IROR, however, the burden of cost overruns will be distributed between consumers and equity investors. While consumers will continue to bear the depreciation expense associated with such prudently incurred investment, they will bear only a portion of the return on the investment to finance such cost overruns. Thus, the IROR should lead to savings in construction costs, which will be divided between lower overall costs to consumers and higher returns to investors. The ultimate effect of applying the IROR will be to provide lower cost natural gas to consumers, with just and reasonable

returns to investors.

## 2. Structure

The IROR mechanism should provide significant incentives to control costs without placing risks on investors that inordinately increase the cost of capital since that cost is ultimately paid by consumers. The IROR mechanism cannot be examined in a vacuum. Because the mechanism affects risk and the allowed rates of return on equity, it must be related to other factors that affect the rates, such as applicable tariff provisions. While the IROR mechanism must be evaluated in its entirety and not just on a component-by-component basis, the major elements should be examined before evaluating the expected end-result on rates.

The basic elements of the IROR mechanism are the Cost Performance Ratio and the associated IROR schedule of rates of return. The Cost Performance Ratio is the ratio of Actual Capital Costs (derived from the final construction costs) to the Projected Capital Costs (derived from estimated costs at the start of construction). <sup>30/</sup> The Cost Performance Ratio

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<sup>30/</sup> As explained in more detail below, in Sections III and IV, the ratio is adjusted for both inflation (an adjustment to Actual Costs) and for design and other scope changes (an adjustment to Projected Costs).

measures how well project management has succeeded in controlling the costs of the project. A ratio greater than 1.0 indicates that actual costs are greater than projected or budgeted costs; a ratio less than 1.0 indicates that actual costs are less than projected or budgeted costs.

The IROR schedule specifies an allowed rate of return for each Cost Performance Ratio. With an IROR mechanism, the lower the value of the Cost Performance Ratio, the higher will be the allowed rate of return, and vice-versa. Figure 1 illustrates this concept by showing a hypothetical IROR schedule. The curve in the figure slopes upward to the left, indicating that rates of return increase as actual costs are reduced to, or fall below, targeted costs (that is, the smaller the Cost Performance Ratio, the greater the rate of return).

Figure 1

Hypothetical Incentive  
Rate of Return Mechanism

Rate of  
Return on  
Equity

IROR Schedule

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1.0

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Cost Performance Ratio

"  $\frac{\text{Actual Capital Costs}}{\text{Projected Capital Costs}}$

The Projected Capital Costs of the project are based on the Certification Cost Estimates submitted to the Commission for approval prior to the issuance of final certificates of public convenience and necessity. These will be submitted in base-year prices and will not incorporate an allowance for future inflation. In addition to the direct construction costs, an interest or finance charge will be included to create an incentive to minimize delays in construction. Under the Decision, the Certification Cost Estimate must be compared to the earlier cost estimate submitted by the project sponsors in 1977, to see if the new estimate "materially and unreasonably exceeds" the earlier estimate. (Decision at 36-37.)

The Actual Capital Costs of the project are the direct costs of construction determined after two adjustments. First, since Projected Costs are calculated in base-year prices with no allowance for inflation, the Actual Capital Costs must be adjusted downwards (or deflated) to remove the effects of general inflation in the U.S. economy, in order to produce a measure of cost overrun for the project absent the effects of inflation. It is not equitable to penalize investors for their inability to estimate future inflation rates; thus, an inflation adjustment mechanism is specified to remove the

effects of economy-wide inflation from Actual Capital Costs. Second, finance or interest charges are added to the direct costs.

Finally, it is unreasonable to penalize the equity investors for certain major events beyond their control that significantly increase construction costs if such events could not reasonably have been anticipated by the project sponsors in preparing their cost estimates. Examples of such events include war, natural disasters, design changes compelled by changes in government laws or regulations, and delays caused by government. Such events are defined as Changes in Scope, and the Projected Capital Costs will be adjusted to reflect these changes. This Order specifies the allowed Change in Scope events, and the procedures for altering the Projected Capital Costs to reflect these changes.

A full specification of the IROR structure must begin with the concept that the IROR schedule is to provide an opportunity for project sponsors to earn a rate of return adequate to attract capital so as to compensate investors for the financial and business risks of the project. 31/ This return would be earned at the expected Cost Performance

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31/ This requirement is fully discussed below; see Section II.B.3 (the Operation Phase Rate).

Ratio. This rate of return is termed the Center Rate of Return (and the associated Cost Performance Ratio is the Center Point). If the realized Cost Performance Ratio is greater than the Center Rate, the IROR will be less than the Center Rate and vice-versa.

By this Order the Commission establishes a value for the Center Rate of Return which should compensate equity investors for the financial and business risks of investing in this project. This will be the sum of an "Operation Phase Rate" and two "risk premiums," a "Project Risk Premium" and an "IROR Risk Premium". The Operation Phase Rate is a rate of return to compensate investors for the risks incurred during the operation of the pipeline after construction is complete.

The Decision contemplates that tariff provisions during operation of the pipeline will be such that the risks during operation will be shared by gas consumers and equity investors. The service interruption provisions of the project tariffs will guarantee debt service once operations commence, but equity will remain at risk. The return on equity will be proportionate to the level of service performed, and for extended total service interruptions the return of equity will also be at risk. The Commission in this Order evaluates the remaining risks borne by investors, and compares them

with the risks of investing in conventional lower-48 natural gas pipelines in order to determine a reasonable value for the Operation Phase Rate. This rate of return will be the rate actually used to calculate the transportation charges of the project under the initial tariff approved by the Commission. This rate will also be used to calculate the allowance for equity funds used during construction in determining the rate base of the project. 32/

The Project Risk Premium is to compensate investors for the unusual risks of non-completion, and other risks borne by investors during the construction of the pipeline. It will be added to the Operation Phase Rate. The Decision requires that construction risks are to be borne by investors or other project beneficiaries and not by consumers during construction, (Decision at 120-21) and that charges to customers may not commence prior to the "completion and commissioning of operation of the system" (Decision at 37-38). 33/ In this Order

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32/ While it will be the rate applied to the pro forma tariffs, the Operation Phase Rate may change over time once the pipeline is in operation, to remain comparable with rates of return earned on other investments having similar risks. See Section VI.B.8. (Review of Equity Rate of Returns).

33/ See Section VI.A.1 (Billing Commencement Date) for an analysis of this phrase.

the Commission evaluates these risks, and establishes values for the Project Risk Premium to compensate equity investors for bearing them.

Because the final costs of construction are unknown, the use of the IROR mechanism introduces uncertainty as to the ultimate rate of return that will be earned by the sponsors. For this reason, a second premium is added to the Operation Phase Rate, an IROR Risk Premium. This will compensate investors for risks created by the use of an IROR mechanism.

The Center Rate of Return is the sum of the Operation Phase Rate, the Project Risk Premium, and the IROR Risk Premium. This will be the rate of return allowed when actual costs (adjusted for inflation) equal expected costs (adjusted for scope changes). For higher values of the Cost Performance Ratio, the Incentive Rate will be reduced; cost growth will result in lower rates of return on equity. The extent of this reduction (or increase, if the Cost Performance Ratio is less than the Center Point) is determined by the Marginal Rate of Return.

The Marginal Rate of Return is an analytical concept used to derive the IROR schedule. It is the rate of return implicitly allowed on incremental investment either above or below base estimates. A low Marginal Rate would mean that the Incentive Rate will decline rapidly as cost increases

occur; a high Marginal Rate would mean that the Incentive Rate will decline only slightly as cost increases occur.

The Commission does not intend to use two rates of return, one on projected costs and one on overruns or under-runs. Rather, a single Incentive Rate will be earned on all investment in the project; but this rate will be a weighted average of the Center Rate and the Marginal Rate. By simple mathematics, the averaging process gives more weight to the Marginal Rate as the Cost Performance Ratio increases. Thus, the Marginal Rate plays the major role in determining the incentive to reduce costs. To provide this incentive, the Marginal Rate must be low enough to make an investment in cost increases unattractive.

Though the President's Decision contemplated that the allowed rate of return would be variable, the Commission has previously recognized that an unusually high or low rate of return allowed over the 25-year (or longer) operating life of the pipeline could create complications for both future Commission regulation of the pipeline and future financing of expansions or additions. 34/ Consequently, the Commission

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34/ See Order No. 17 (Docket No. RM78-12) (Dec. 1, 1978); See also Notice of Proposed Rulemaking, Docket No. RM78-12 (May 8, 1978); Revised Notice of Proposed Rulemaking, Docket No. RM78-12 (Sept. 15, 1978).

introduced the concept of a one-time adjustment to rate base that would have the same effect as varying the allowed rate of return over the operating life of the pipeline. The one-time adjustment is based on the principle that the same level of profitability can be achieved by allowing the Incentive Rate to be earned on a normal, unadjusted rate base, or by allowing the Operation Phase Rate to be earned on an appropriately adjusted rate base. By adjusting the rate base the same effect can be achieved as varying the allowed rate of return.

The one-time adjustment to the equity investment in the rate base of the project will be made shortly after the operation of the pipeline commences. Thereafter the Operation Phase Rate will be earned on the adjusted rate base. The size of the adjustment to the equity investment in the rate base will be derived from standard discounted cash-flow analyses. The one-time adjustment is such that the present worth of the return on equity and return of equity over the operating life of the pipeline (based on the Operation Phase Rate) is equivalent to the present worth of the returns from applying the Incentive Rate to the normal, unadjusted rate base.

**B. Components****1. The Cost Performance Ratio**

The basic concept of the Cost Performance Ratio was described above. This section provides a more specific description of its determination and use.

The Cost Performance Ratio is used to measure the degree of cost growth or reduction from the projected costs of the project. It is also used to measure the success of project management in reducing or controlling costs of construction. The measurement of cost growth or the success of management in reducing costs must take into account the following four factors:

(1) Cost growth due to general inflation within the economy can not be reduced or controlled by management and should not be included in the measurement of management's performance in reducing costs.

(2) Cost growth due to an extension of the construction schedule is as important as an increase in direct construction costs and should be included in the measurement of management's cost control performance. A longer construction schedule adds finance or interest charges to total costs, and these will be paid by the gas consumer.

(3) Certain major events may occur which could not have been anticipated by management, the cost impact of which are largely beyond the control of management, and which substantially increase costs. The impact of these events should not be included in the measurement of management's performance in controlling costs.

(4) The measurement of cost growth should be as simple and as uncomplicated as possible to avoid controversy about its use, and thereby avoid major administrative burdens on the Commission, the Federal Inspector, and the project management in implementing the IROR mechanism.

The measurement of cost growth established by the Commission in this Order (the Cost Performance Ratio) meets these four criteria. The Cost Performance Ratio is simply the ratio of actual costs to projected costs: Cost Performance Ratio equals the Deflated Actual Capital Costs divided by the Projected Capital Costs.

The Deflated Actual Capital Costs for the project will be calculated in three steps. First, the direct construction costs (labor, materials, services, etc.) actually

incurred in the construction of the project will be totaled for each quarter. 35/

Second, these quarterly expenditures will be deflated back to base-year prices by the use of a composite inflation index. This index is discussed in greater detail below in Section III. This index is designed to remove the effect of general inflation on those construction costs.

Finally, an interest charge or finance charge will be added to the total direct costs of the project. This charge, hereafter referred to as the Finance Charge, will be based on a Real Rate of Return. 36/ Since the effect of inflation has been removed from the calculation of direct costs, the rate of interest or return on equity used to calculate the Finance Charge will be a "real" rate with the effect

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35/ In their initial comments, the project sponsors request the Commission to clarify when a particular expenditure will be deemed to have occurred since this is important for the inflation adjustment mechanism (Joint Comments at Tab. 2, p. 11). The Commission agrees with the sponsors that an expenditure for materials or services should be deemed to have occurred when the actual payment for those materials or services is made.

36/ This Finance Charge was referred to as an allowance for funds used during construction (AFUDC) in the Notice of April 6.

of inflation also removed. Actual market rates of interest in our economy today reflect or compensate investors for their expectations about future rates of inflation since inflation reduces the worth of their return from the investment.

The Projected Capital Costs (the denominator of the Cost Performance Ratio) will be calculated in four steps. First, the direct costs included in the Certification Cost Estimate, to be submitted to the Commission prior to the receipt of a final certificate of public convenience and necessity, will be divided into quarters depending on when they are expected to be incurred. Since these costs are already calculated from base-year prices, no adjustment for inflation is required.

Between the time the Certification Cost Estimate is prepared and the time when the final design and cost estimate is submitted to the Federal Inspector, 37/ certain changes in design or schedule may occur. The second step will be to adjust the Certification Cost Estimate to reflect these changes in design or schedule. 38/

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37/ This final submission is mandated by the President's Decision. Decision at 29.

38/ Prices, however, will not be changed from those that prevailed in the base year for cost estimation.

After construction begins, certain events may occur which the Commission defines to be Changes in Scope for the project. (For a more complete description of these events, see Section IV.) Direct costs in the Certification Estimate will, in the third step, be adjusted to reflect the impact of these Changes in Scope should they occur.

Finally, a Finance Charge will be added to the adjusted direct costs using the Real Rate of Return to obtain the Projected Capital Costs.

The Commission believes that the ratio of these two measures of capital costs (Deflated Actual Capital Costs and Projected Capital Costs) provides the best practical measure of cost growth or overruns to be used to determine the extent of the project management's success in controlling costs. This Cost Performance Ratio meets the four criteria discussed above.

The Commission believes that it is important to include some type of interest charge or finance charge in the calculation of the Cost Performance Ratio since these charges are just as much a cost to consumers as is the cost of steel, labor, valves, etc. However, the Finance Charge should be calculated from a "real" or inflation-free rate of return. Calculation of such a real rate return is inherently

imprecise. The "real" rate is derived by subtracting an estimate of the rate of future inflation, expected by current investors from current market rates of interest and rates of return.

The Commission estimates the Real Rate to be 5 percent. This estimate is based on the following assumptions:

(1) 25 percent equity capitalization earning a 14 percent return (a rate of return generally representative of current rates required by equity investors); (2) 75 percent debt capitalization earning an 11 percent interest rate (a rate generally representative of current rates of interest, for example the prime rate); and (3) an investor expectation of a long term inflation rate of 7 percent (a rate representative of recent rates of inflation in the U.S. economy).

The Real Rate can then be derived from:

$$\begin{aligned} & (0.25)(14\% - 7\%) + (0.75)(11\% - 7\%) \\ & = (0.25)(7\%) + (0.75)(4\%) \\ & = 1.75\% + 3\% \\ & = 5\% \text{ (rounded)} \end{aligned}$$

The project sponsors, with almost no justification, propose instead a rate of 1 percent. Though we are not confident that 5 percent is precisely the correct number, we are certain that 1 percent is too low.

- A second criticism by the sponsors, put forward as a footnote, concerns the "cut off" date for accrual

of the Finance Charge. 39/ The intent of this footnote is unclear, but it shows a misunderstanding of the relationship between the accrual of the Finance Charge in calculating the Cost Performance Ratio, the accrual of AFUDC in the rate base of each pipeline segment, and the billing commencement date. The distinction between these concepts is important, and any confusion must be dispelled. Accrual of a Finance Charge in the Actual Capital Costs, and thus in the numerator of the Cost Performance Ratio, will cease for each segment of the project (Alaska or Northern Border) when construction of that segment has been completed even if, for whatever reason, another segment is not complete. The intent of this provision is to avoid penalizing investors in one segment for delay in another segment or in the start-up of gas production. 40/

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39/ Joint Comments at 21 n. 12.

40/ The Commission Staff in their comments propose a variation on this approach which would add the "real" Finance Charge no longer being accrued in the Cost Performance Ratio of a completed segment, to the Cost Performance Ratio of those segments not completed, including if possible segments in Canada. (Initial Staff Comments at 48) This idea has some theoretical appeal since it would require the late segments to bear an even greater Finance Charge in the Cost Performance Ratio, and thus give the investors

(Footnote continued on next page).

This procedure for including a Finance Charge derived from the Real Rate of Return in the Cost Performance Ratio of each segment must not be confused with Commission procedures for the inclusion of AFUDC in the actual rate base of each segment. Inclusion of AFUDC in the actual rate base will be calculated from rates of interest actually incurred during construction on project debt and the rate of return on equity allowed for purposes of calculating AFUDC. Accrual of AFUDC in the rate base of each segment will continue until billing under the full cost-of-service provisions of the tariff commences. For a more complete discussion of the billing commencement date, see Section VI.A.1.

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40/ (Footnote cont'd.)

even greater incentive to complete construction. However, insofar as we would be obliged to further compensate investors for the additional risk this requirement would add, we do not believe its additional incentive benefits outweigh the additional costs that further compensation may impose on customers.

## 2. The Center Point

The Center Point Cost Performance Ratio should represent the best current estimate of the actual costs of the project, including any cost overruns relative to the Certification Cost Estimate approved by the Commission. 41/. This ratio has two significant functions.

First, if the Certification Cost Estimate, including likely cost overruns, "materially and unreasonably exceeds" the March, 1977 cost estimate filed by the project sponsor with the Federal Power Commission, then the Commission must carry out the mandate in the President's Decision to review the project and determine whether a certificate of public convenience and necessity should be granted. 41a/ In this review, both the Certification Cost Estimate and the Center Point Cost Performance Ratio are highly significant. The Certification Cost Estimate is important because it indicates, when compared with the March, 1977 estimate and after making proper allowances for price inflation, the growth in the projected costs as a result of the study and work on this project between March, 1977 and the preparation

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41/ In statistical terms the Center Point is obtained by adding together each possible level of the Cost Performance Ratio multiplied by the probability of that Cost Performance Ratio occurring.

41a/ Decision at 36.

of the Certification Estimate.

The Center Point Cost Performance Ratio is important to this review because it also may have changed as a result of the study and work on the project. The Certification Cost Estimate will likely have grown from March, 1977 as a result of detailed planning and design, but the expected cost overrun associated with that estimate may have been altered, and hopefully reduced, by that planning and design. Thus, the Commission believes that the Center Point Cost Performance Ratio must be a part of the comparison of the Certification Cost Estimate with the March 1977 estimate since that review should consider whether or not the expectation of cost overrun has changed from that associated with the March 1977 cost estimates.

Second, the Center Point Ratio is important because it is the target outcome of the project. For example, a Center Point of 1.2 would indicate that a further 20 percent increase in costs is expected from the Certification Estimate, and that this would be the target for IROR purposes. The President's Decision envisioned that the Certification Cost Estimate would be used as the "basis for fixing a variable rate of return on equity that would reward the applicant for project completion under budgeted cost and penalize the

applicant for project completion above the budget cost." 42/ The Commission, therefore, after having determined that the Certification Cost Estimate does not unreasonably exceed the 1977 estimate, must select from all the possible outcomes a target Cost Performance Ratio to use as the Center Point in structuring the IROR schedule.

Common observation as well as historical and statistical studies 43/ of many different types of large projects have revealed a tendency for the estimates of total cost-to-completion to increase as a project moves over time from initial conception to completion. In the early stages of a project this growth often reflects the study required to turn an idea into a detailed set of plans and specifications. In the process of research, evaluation, planning, and budgeting, natural initial optimism is tempered by more realistic appraisals; and in the usual case, unperceived complexities are discovered and the difficulty of the required tasks becomes better understood.

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42/ Decision at 37.

43/ See, e.g., W. Mead, G. W. Rogers, & R. Z. Smith, Transporting Natural Gas from the Arctic: The Alternative Systems, 89-94 (1977).

It would have been unrealistic had the President's Decision used the project sponsors' cost estimate in March 1977 as the basis for evaluating the economics of the project. Instead, the Decision factored in cost growth estimates of approximately 30 percent for the Alaska segment and 10 percent for the Northern Border segment, in the evaluations leading to approval of the project. 44/ The estimates that cost growth in excess

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44/ The President's Decision contains two estimates of the extent of likely cost overruns in Alaska. The Report accompanying the Decision states that "[o]verall, it has been estimated that cost overruns of 30 percent or more should be expected in Alaska and Canada. . ." Decision at 150. The table of capital cost estimates on p. 157 of the Report, however, shows a 24 percent cost increase from the Base Case estimate in current or inflated dollars for Alaska. For Northern Border, the expected overrun is 10 percent. All of these estimates include finance charges or an allowance for funds used during construction derived from market rates of interest and rates of return on equity. The State of New York in its initial comments (p. 5) points out that the estimates of cost overruns in the Decision do not include an adjustment for inflation and route changes or other changes in scope. These points, however, do not mean that to the extent the Commission excuses cost increases resulting from design changes or change in scope events, the expected overruns should be less than estimated in the Decision. Inflation is fully accounted for in the Decision by the use of constant 1975 prices; moreover we cannot presume that the Decision considered change in scope variables in estimating costs for a given system.

of 30 percent for Alaska and 10 percent for Northern Border were not likely to occur were one basis for the finding that the project was in the public interest.

Several implications follow. Looking at the project at the time of submission of the Certification Estimate with the benefit of two or more years of intensive study, evaluation, planning, programming, and budgeting by the sponsors, it would be surprising if the new estimate did not reveal some cost-growth compared to the March, 1977 estimate, even allowing for price inflation. This would be a natural phenomenon reflecting, at a minimum, a better understanding and perspective on the project. 45/

Another implication is that after two or more years of work on this project, the Certification Cost Estimate should be a more accurate estimate of what the actual cost of the project will be upon its completion than the cost estimate made in 1977. It would be surprising to realize as large an

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45/ The comments by the project sponsors list a number of reasons why they now expect the Certification Estimate to exceed the March 1977 estimate: (1) cost of restoring Alyeska work camps; (2) cost of restructuring Alyeska communications system; (3) higher estimate of costs to obtain Governmental approvals; and (4) greater project management expenses. Joint Comments at 11-15.

amount of cost growth from the Certification Estimate as the expected amount of cost growth from the 1977 estimates. 46/

Because the Certification Cost Estimate will be the basis of the Commission's certification proceeding and the cornerstone of the allowed rate of return for this project, it is vital that the Commission have the most accurate and realistic set of cost estimates that can be obtained. There is need to deter both overly optimistic projections which might be offered in the hope that they would promote final certification of the project, and overly pessimistic projections which provide a large margin for error in cost estimates or an implicit allowance for large cost increases. The latter type of estimate would vitiate the intended motivational aspects of the IROR and could result in unreasonably high rates of return.

Considering that a 30 percent allowance for cost growth on the Alaska segment and 10 percent on Northern Border were allowed for in the President's Decision, it is unlikely that, on the sole basis that estimated costs had increased by 30

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46/ The project sponsors, however, seem to expect as much cost growth from Certification Estimate as did the President from the March 1977 estimate. Joint Comments at 31. They argue that a 30 percent increase is likely from the Alaskan Certification Estimate and 20 % for Northern Border.

percent for the Alaska segment and 10 percent for Northern Border, the Commission could make a negative finding concerning the public interest of the project. On the other hand, if there were to be a substantial increase in the Certification Estimate over the March 1977 estimate without a substantial decrease in the expected cost overrun from the Certification Estimate, it would seem to follow that either the initial cost estimates used in the 1977 evaluation were badly mistaken or the nature of the project had changed considerably. In either situation the Commission would need to take these developments into consideration in connection with its certification responsibilities. 47/

The Commission has embodied these considerations in a procedure for determining the Center Point. It is contained in Condition No. 12 of the attached Terms and Conditions. The Incentive Rate of Return is based solely on the Certification Cost Estimate. However, in determining the value of the Center Point Cost Performance Ratio, the Commission will take into consideration the relationship between the Certification Cost Estimate and the March 1977

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47/ In this connection, the Commission notes with concern the sponsors' comments regarding cost growth cited in footnotes 45 and 46, supra.

estimate, i.e., the cost growth between these two estimates during the intervening period. If a substantial amount of cost growth had already occurred, it would seem in accord with the basic thrust of the Presidential Decision to assume that most of the projected 30 percent cost growth had already occurred and that it would be unreasonable to expect a sizable amount of cost growth in the future. Conversely, should the two estimates show very little cost growth in the intervening period, it would seem reasonable to expect that most of the 30 percent cost growth envisioned in the Presidential Decision would occur in the future. 48/

The formula in Condition No. 12 expresses this concept mathematically. For example, if the Certification Cost Estimate were to exceed the March 1977 estimate for the Alaska segment by 20 percent, then in accord with the President's Decision, the Center Point would be set so as

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48/ In response to earlier concern by the project sponsors, the Commission, in Order No. 17, made it clear that the Certification Estimate will be the basis for the IROR mechanism. Order No. 17, "Order Attaching Incentive Rate of Return Conditions to Certificates of Public Convenience and Necessity," Docket No. RM78-12 (Dec. 1, 1978). The Projected Capital Costs will be derived from the Certification Estimate. However, the Commission believes that it must consider the Decision's findings concerning likely overruns in choosing a Center Point.

to anticipate a further 10 percent cost growth between the time of the Certification Cost Estimate and completion of the project. 49/ To cite another hypothetical example, were the Certification Cost Estimate to exactly equal the March 1977 estimate then the formula would imply that the Center Point should be 1.3, which would provide for the 30 percent cost growth the Presidential Decision estimated would take place.

Of course, it may be that the project had so changed in nature and scope that the two cost estimates could be linked in the process of setting the Center Point. If this were so, the project sponsors should so inform the Commission and provide a detailed explanation of the nature of the changes which had caused the discontinuity in the project so that the Commission could have this information in conjunction with the certification function as well as for establishing a Center Point.

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49/ In all cases allowance should be made for inflation so that the comparisons involve calculation of real growth, i.e., growth in resource requirements and not prices.

In the absence of an assertion of a major change in the basic nature of the project from that assumed in the Decision, the Commission will relate its determination of the Center Point to the cost growth that has taken place during the last two years. The mathematical relationship for the Alaska segment will be: Center Point = 1.3 x (March 1977 estimate in base year prices + Finance Charge) / (Certification Cost Estimate + Finance Charge). For the Northern Border segment the relationship will be: Center Point = 1.1 x (March, 1977 estimate in base year prices + Finance Charge) / (Certification Cost Estimate + Finance Charge). Base-year prices are those used in preparing the Certification Estimate, and the Finance Charge is calculated from the Real Rate of Return defined below. 50/

In their comments on the Commission's April 6 notice, where the above procedure for determining the Center Point was proposed, the project sponsors criticize this proposal as basing the IROR mechanism on the March 1977 estimates submitted to this Commission and the President. As we stated in Order No. 17, the Commission does not intend to

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50/ The Commission Staff in its initial comments (pages 58 and 60) supports this procedure and puts forth a number of the arguments given here advocating this procedure.

base the IROR mechanism on the March 1977 estimates. The attached terms and conditions clearly state that the Projected Capital Costs and the Cost Performance Ratio will be based on the Certification Estimates to be submitted to the Commission sometime in the future.

The Commission must have some basis, however, for determining the Center Point of the IROR schedule. The only information available to us now about the likely cost growth or the ultimate costs of the project including overruns are the conclusions reached in the President's Decision based on the March 1977 estimates. Those conclusions were based upon reasoned comparisons between the cost estimates of the competing projects, actual experience in the Alyeska System, the Recommendation submitted to the President by this Commission, and a number of intragency task force studies and numerous other information sources. Using this information, the Commission has established the above procedure to determine the Center Point.

The Commission, however, anticipates that additional information will be made available to us by the project sponsors about the expected ultimate cost of the project at the time they submit the certification cost estimates. If

this information is substantially different from that relied upon by the President in reaching his conclusions about cost growth, then the Commission would have to reconsider the issue of where the Center Point should be set. 51/ In such a situation the Commission would envision setting the Center Point as part of its overall review of Project costs using a procedure such as that set out below.

If the project sponsors believe that a major change in the basic nature of the project from that assumed in the Decision has occurred, and thus the above procedure for setting the Center Point is no longer applicable, then the sponsors, as part of their respective submissions of certification cost estimates, must at a minimum present evidence to the Commission on the following subjects:

- (1) The nature of the changes in the project from that assumed at the time of the Decision, including a

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51/ The project sponsors in their comments seem to advocate that the Commission now set a Center Point of 1.3 for Alaska and 1.2 for Northern Border based on the certification cost estimates which have not yet been submitted to us. The Commission has no factual basis or evidence to support such a determination. Since the Decision is the best estimate of the cost of the project available to us, the procedure or formula described above is the only method we can justify for setting the Center Point until such as time the project sponsors may provide us with additional evidence.

detailed explanation of why the Certification Cost Estimate has changed from the March, 1977 estimate. The Commission will later specify certain cost formats which the sponsors shall follow in submitting their Certification Estimates in order to allow the Commission to better assess the reason for the change in costs. (See Condition 8 of the attached terms and conditions). This information will assist the Commission in determining if the Certification Estimates materially and unreasonably exceed the March 1977 estimates as required by the Decision.

- (2) The value or benefit to the Nation and gas consumers of construction of this project in light of the revised cost estimates. In other words, the sponsors must demonstrate that the project is still in the public interest given the changes in the project since the Decision.
- (3) The cost increases or cost overruns above the Certification Estimates that may reasonably be expected to occur. The sponsors should explain what eventualities or contingencies are provided for in the Certification Estimates and the contingencies for which no costs have been included. As part of the

Certification Estimate, the sponsors should provide an analysis of the events that could cause cost increases from the Certification Estimate, the likelihood of these events, and their impact on costs. The Commission expects that the Certification Estimates will only include costs resulting from normal conditions to be expected during construction. Abnormal or unlikely events that could increase costs will be analyzed as part of the sponsors' submission concerning potential cost overruns from the Certification Estimate. 52/ The sponsors' analysis of the potential for cost increases from the Certification Estimate will then be used by the Commission in determining the Center Point. If a convincing case is made that the potential for cost increases beyond the Certification Estimate is substantial, then a reasonable value for the Center Point may be substantially greater than one. In any event, the Commission considers it unlikely that the Center Point would be less than one if the Certification Estimate is based on normal or probable conditions.

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52/ Since the Certification Estimate will be revised as a result of design changes and other events prior to the Final Design, and for a limited number of Change in Scope events after the final design (see Section IV), the analysis of cost overruns should distinguish between events that are covered by the Change in Scope mechanism and those that are not.

### 3. The Operation Phase Rate

The Operation Phase Rate of return on equity is that rate which will compensate equity investors for the risks incurred during the actual operation of the pipeline. This rate will be used to calculate transportation charges pursuant to the tariff approved by the Commission after the one-time adjustment to the rate base. 53/

By way of background, the Commission notes that the natural gas transmission industry has had limited experience with project financing; the most expensive projects undertaken have been in the \$500 million to \$1.5 billion range. However, the ANGTS project is unique in that no other project of this magnitude and character has been undertaken.

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53/ This rate will also be used to determine the equity component of the Allowance For Funds Used During Construction in the rate base of the project. Originally in Order No. 17, the Commission required that the AFUDC rate would be the Operation Phase Rate plus the Project Risk Premium. However, the methodology for determining the Project Risk Premium proposed by the project sponsor required knowing the AFUDC rate before calculating the Project Risk Premium. In order to solve this dilemma, the Commission now requires the use of the Operation Phase Rate to calculate AFUDC. However, as a compensating adjustment, the Project Risk Premium, and thus the Center Rate, have been increased from what they would have been assuming the higher AFUDC rate. See Section II.B.4., discussing the Project Risk Premium.

The Commission has adopted a general approach for determining the Operation Phase Rate. First, an estimate was made of the range of rates of return that appears reasonable, considering current financial market conditions and the risks of investing in conventional lower-48 natural gas pipelines. Second, the Commission has compared the operating risks of the Alaskan gas pipeline with the risks normally encountered during operation of conventional pipelines. Based on this comparison of risks, the Commission has determined that the Operation Phase Rate should be within the range of rates that is reasonable for conventional pipelines. 54/

A survey of rate cases (mostly settlements) during the years 1977, 1978, and early 1979, discloses that the rates of return allowed for lower-48 natural gas pipelines have been between 10.68 percent and 15.0 percent. The majority of returns fell within the narrower range of 12 to 14 percent. This survey is the point of departure for our analysis.

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54/ Order No. 17 provides that the Operation Phase Rate shall be set by the Commission "within the general range of rates of return for other pipelines with similar operating risks" (Terms and Conditions, No. 12).

Apart from simply reviewing values allowed in the past, there are a number of alternative approaches used by financial analysts for estimating rates of return for utility rate-setting purposes. Without attempting to select a preferred approach from the array of methodological options, the Commission has examined three procedures to see what each implies as an appropriate reference value for lower-48 pipelines. No procedure can precisely determine a just and reasonable rate of return. Therefore, the Commission must exercise its judgment after reviewing the relevant information in order to determine an appropriate value for the Operation Phase Rate.

The general standards for establishing a just and reasonable return on common equity were set forth by the Supreme Court:

[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. 55/

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55/ FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944).

At the outset, it is readily acknowledged that assembling samples of enterprises "with corresponding risks" is a formidable task. It is difficult to specify risk measures that are both conceptually valid and also work. For this reason, virtually all methods used for recommending allowed rates of return share the weakness of relying on data for entities that may not be precisely comparable in risk.

The often-used "comparable earnings approach" examines rates of return on common equity earned in other businesses or industries with risks comparable to those of the natural gas pipeline industry. In their comments, Alaskan Northwest and Northern Border provided information as to returns earned by industry groups for the years 1973-1978. Looking at the average rate of return for all industries combined over the six-year period, the range has been approximately 11.7 to 15.4 percent. 56/

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56/ Joint Comments, Tab 1. Data for natural gas utilities show returns in the range of 11.9-16.2 percent.

Another popular technique is the familiar "discounted cash flow" approach. This method attempts to determine the investors' required rate of return by estimating their expected return (dividends and capital appreciation) on the market price of common stock. The application of the discounted cash flow approach to the ANGTS indicates that the investors' required rate of return for natural gas pipeline companies is somewhere in the range of 14 to 16 percent. 57/

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57/ Based on recent years' data for Moody's Natural Gas Transmission Company Average, it appears reasonable that investors might expect return on book equity to be 15-16 percent and dividend payout ratios to be 40-50 percent. (See Moody's Public Utility Manual at a16 (1978). Using growth from retained earnings as a proxy for growth in dividends, such data implies an expected growth in dividends of 7.5 to 9.6 percent. (Growth from retained earnings equals return on book equity times the retention rate, or 15 to 16 percent multiplied by 1 minus 40 to 50 percent). Combined with the average dividend yield of 6.7 percent for the first quarter of 1979, a range of 14.2 to 16.3 percent is produced. Since the market-to-book ratio of Moody's Natural Gas Transmission Company Average in recent years has fluctuated around 1.0, there is reason to believe that this calculated range is reasonable insofar as it approximates the earned returns on book equity in recent years.

Sponsors' consultant, also using a discounted cash flow approach, arrived at a range of 15.7 to 16.7 percent. (Joint Comments, Tab A.) In our judgment, this selection of a 9 to 10 percent expected growth in dividends is biased on the high side because of an incomplete and inadequate implementation of this approach. For example, we note the absence of historical book value growth rates for Moody's Natural Gas Transmission Company

(Footnote continued on next page).

The third approach examined by the Commission involves estimating the difference in return that equity investors require over the rate of interest prevailing on bonds. Since market-determined rates of interest are widely available and accepted as meaningful, a measure of the differential between equity return and prevailing interest rates using this information is practical and provides a plausible guide to the equity investors' required return.

Based on the proposition that over long periods an equilibrium is established between investors' earned returns and their required returns, one way to determine a differential between equity and debt returns is to observe the difference between returns realized on riskless investments (such as U.S. Government bonds) and returns realized on investments in common stock, namely, dividends

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57/ (Footnote cont'd).

Average even after the sponsors' favorable comments concerning the merit in using them to smooth fluctuations in earnings and to provide a longer term view of potential growth. (Joint Comments at Tab A.) Using the least-squares growth rate in average book value of 8.4 percent for the 1968-1977 period, we can derive an estimate of 15.1 percent for the investor's required return. Furthermore, the assumption of a dividend payout ratio as high as 60 percent in the analysis of the expected dividend growth rate was completely unsupported.

and capital appreciation. Using U.S. Treasury bond interest rates as the riskless rate measure, the equity differential has averaged between 5 and 6 percent over lengthy historical periods. 58/ Thus, adding these equity differentials to current Treasury bond interest rates of about 9 percent produces a required equity return in the range of 14 to 15 percent. 59/

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58/ Ibbotson & Sinquefeld, "Stocks, Bonds, Bills and Inflation: Year by Year Historical Returns (1926-74)." Jnl. Bus. (Jan 1976); "Stocks, Bonds, Bills and Inflation: The Past (1926-1976) and the Future (1977-2000)," The Financial Analysts Research Foundation, 1977; see also, Levy "Stocks, Bonds, Bills and Inflation Over 52 Years," Jnl. Portfolio Mngt. at 18-19 (Summer 1978).

59/ Implicit in Hass' analysis of an Operation Phase Rate is a current required return of 15.7 percent for diversified natural gas transmission companies (a "riskless" rate of 9 percent plus an equity "risk premium" of 6.7 percent). See Hass Report at 16-20.

Sponsors' consultant employed the capital asset pricing model, a variant of the risk premium approach, and arrived at a rate of return of 17.33 percent for conventional lower-48 pipeline companies. (Joint Comments, Tab A.) Incorporated in this analysis was a market risk premium of 8.5 percent. The support for a required premium of this magnitude, however, was largely undocumented and unpersuasive. Substituting the 5 to 6 percent premium cited above, the result is a range of 13.9 to 14.9 percent. (Riskless Rate plus Beta times Market Risk Premium or 9.0 percent plus 0.98 times 5 to 6 percent.)

In summary, the Commission's recently allowed rates of return for lower-48 natural gas pipelines have generally fallen within the range of 12-14 percent. In addition, data for recent earned rates of return on common equity and two methods for estimating investors' required rates of return for lower-48 pipelines yield the following ranges:

<u>Estimation Approach</u>	<u>Range of Rates</u>
Comparable Earnings	12 to 15%
Discounted Cash Flow	14 to 16%
Equity Risk Premium	14 to 15%

Given this range of estimates, the Commission must exercise its judgment in determining the reference value for lower-48 pipelines. On balance, the Commission believes that under current market conditions a rate of return in the range of 12 to 15 percent is appropriate to use as a basis for setting the Operation Phase Rate for the ANGTS.

To use this range as a guide for setting the Operation Phase Rate, the Commission must assess how the risk exposure of investors in the ANGTS project during operation compares to the risk-exposure of pipeline investors in the lower-48 states. The Commission believes that the greatest risks faced by investors in the ANGTS will occur during the construction phase. <sup>60/</sup> The risk exposure the Commission is

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<sup>60/</sup> The Project Risk Premium is intended to compensate investors for these risks. See Section II.B.4 (Project Risk Premium).

is attempting to evaluate here concerns the relative risks of the ANGTS and lower-48 pipelines during the operational phase. To compare risks, we first examine why the Alaska project may have greater operating risks than lower-48 pipelines, then examine why risks during operation may be less than those faced by other pipelines. Finally, we weigh and balance the various factors.

Operating aspects of the Alaska project that may be regarded as more risky than operating conditions for lower-48 pipelines are the following:

Arctic operating environment. The project in Alaska will be operating in a harsh environment. The ANGTS could experience problems such as thaw settlement or frost heave affecting the reliability of operations. Innovative techniques such as gas refrigeration will have to be used because of the environment. Environmental restrictions, remote locations, and severe climate may affect the ability to repair the pipeline in the event of a service interruption.

High pressure pipeline. The project will be operating at higher pressure than is conventional. Although the Commission does not expect the higher pressure to affect operating reliability, confirmation will only come through operating experience.

High cost gas. Because of relatively high transportation costs, the gas transported through this system will be expensive compared to other sources of supply. Large cost overruns or partial service interruptions could result in even greater costs per unit of gas. Though the tariff approved by the Commission will allow for rates to recover the full cost of service once service commences (with the exception of equity charges in the event of service interruptions), difficulties in marketing the gas or in collecting the allowed revenues could conceivably occur.

Low equity capitalization. The proportion of equity in the capitalization of the pipeline is expected to be approximately 25 percent, in contrast to an industry average of about 50 percent. In the absence of other considerations, the higher degree of leverage increases the risks to equity investors should there be a diminution of revenues because the fixed costs of the project, including debt service must be paid prior to any return to equity. 61/

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61/ Leverage should not be evaluated alone; it must be considered along with other factors of which the most important is the cost-of-service tariff which largely reduces the risk associated with a high proportion of equity investment.

There are also very significant risk-reducing features of this proposal. The most important are:

Cost-of-service form of tariff. By this Order, the project is granted a cost-of-service form of tariff instead of the conventional fixed-rate form. The cost-of-service tariff allows the project to charge rates adequate to recover its full cost of service, even if costs or throughput change over time, without the need for first filing a new rate schedule or obtaining this Commission's approval. In contrast to the fixed-rate tariff, changes in costs or throughput volumes are reflected immediately in the pipeline's rates, rather than after some period required for processing a rate-change application.

The commitment to allow a cost-of-service tariff is a major factor that offsets much of the risk exposure of investors in the ANGTS. The cost-of-service mechanism greatly reduces the risk of inability to earn an allowed return due to increases in cost or reduction in volumes. 62/

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62/ Some risk that estimated throughput volumes may not be attained continues to exist. For example, as discussed more fully in the section on tariffs, the segment may be unable to transport the contract quantities because of a pipeline operating problem. If the diminution of service over a one month period amounts to more than 10 percent of contract throughput, the return on equity

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With respect to the proposed capitalization, sponsors' consultant urges that the Commission continue to acknowledge the risk increasing effects of financial leverage by allowing a higher equity return for the "thinner" equity of the project. However, we feel that there is much merit in the Staff's argument that the cost-of-service and service interruption provisions in the tariff largely offset the financial risks associated with debt financing. Considering the risks associated with the relative proportions of debt to equity in the capital structure, we believe that the cost of service tariff provisions offset the high degree of leverage proposed by the sponsors and consequently, we feel that ANGTS will face lower financial risks than would conventional pipelines with the same equity capitalization but without the cost of service tariff.

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62/ (Footnote cont'd).

will be proportionately reduced. Provision is made for possible makeup transportation at a later date. If all service is interrupted for more than 30 days (a most unlikely event), the return of equity may also be forfeited if the Commission finds that the cause of the interruption was within the project sponsors' control.

Tracking of costs by shippers. In order to further assure that revenues are adequate to cover the cost of service of the project, the Commission's policy will be to allow automatic tracking of Alaska gas transportation costs in the tariffs of gas shippers who are interstate pipelines under our jurisdiction. The exact form or nature of the tracking mechanism must await specific applications from shippers to modify or amend their tariffs and may differ from shipper to shipper.

Large reserves-to-production ratio. The reserves of gas at Prudhoe Bay are very large (at least 26 trillion cubic feet) and can supply gas for the pipeline at a rate of 2.4 billion cubic feet per day for at least 20 years without exhausting the reserves. This reserve-to-production ratio is much larger than for most other natural gas pipelines and provides assurance that gas supply will be adequate to allow the full recovery of capital investment in the project. Thus, as compared to most pipelines that have reserve commitments that generate significant risk-exposure, the ANGTS is in an enviable position.

Rolled-in pricing. In order to reduce marketing risks for this relatively high cost gas, the Congress, as part of the Natural Gas Policy Act, directed that the transportation cost and wellhead price for this gas will be "rolled-in" or averaged with cheaper sources of supply and

sold to higher priority users. Thus, even if this gas is more expensive than some other sources of supply, potential problems of marketability are reduced since shippers are assured that they will not have to market this gas separately from other sources of supply.

Weighing all the risk-increasing and the risk-reducing factors, the Commission concludes that the risk exposure of ANGTS investors during the operation phase of the Alaska segment of the project will be somewhat higher than the risk-exposure of investors in the typical or average lower-48 pipeline. Thus, the Commission believes that an allowed Operation Phase Rate near the upper end of the range of rates discussed previously for lower-48 pipelines (12 to 15 percent) is reasonable for the Alaska segment of the project. The Commission selects 14 percent as the Operation Phase Rate for the Alaska segment. 63/

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63/ Sponsors' asserted that the implementation of the comparable earnings approach confirmed the reasonableness of a previously deduced 18% return on common equity for the ANGTS project (as opposed to typical lower-48 pipelines). (Joint Comments at Tab A.) They initially contended, without adequate support, that the ANGTS project should be viewed as a relatively risky enterprise during its operation. This unsubstantiated position presumably underlies the 18% return recommendation. They then attempt to further justify this recommendation merely by noting that the 18% value falls in the upper deciles of the earned returns on common equity for over four thousand

(Footnote continued on next page).

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63/ (Footnote cont'd).

publicly held corporations. The apparent rationale here is that risk and earned returns on common equity are directly related. The sponsors nowhere establish, however, that high earned returns on common equity are necessarily associated with high risk.

Hass recommended 14.4% as the Operation Phase rate for the Alaska segment and 12.5% for the Northern Border segment, Hass Report at 20, while Staff contended that 11.5% and 10.5 percent, respectively, are more appropriate. Initial Comments of the Commission Staff on Company Tariffs and Incentive Rate of Return, Docket No. RM78-12 at 76-77 (May 4, 1979). [Hereinafter Staff Initial Comments]. Both took the position that investors, primarily because of the cost-of-service tariff, would perceive the ANGTS project as being a less risky investment than investments in lower-48 pipelines. However, while Hass' analysis enables one to see the steps leading to his conclusion, Staff's analysis is wholly subjective and no attempt is made to justify the current appropriateness of a 13% allowed return for conventional pipeline companies or how Staff's risk analysis led it to conclude that 10.5 - 11.5 percent is a reasonable range for the ANGTS project. Although the Commission recognizes the risk reducing nature of many of the issues discussed by Staff, we believe that Staff's qualitative analysis does not give sufficient consideration to how the uncertainties associated with the ANGTS project will impact on investors' required returns.

Staff attempted to confirm the reasonableness of its recommendation by duplicating, with some adjustments, the type of risk premium approach employed by Hass. We believe, however, that Staff's version of the Hass approach is flawed in several respects. For example, the 12.9% figure that Staff used as representative of allowed return for natural gas pipeline in 1975 was not shown to be equal to the investors' required return. Furthermore, for the risk premium approach to have any validity, investors' required returns for debt and equity securities must be compared during the same time period. Staff, however, relates this 12.9% figure to a current riskless rate rather than the riskless rate

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The Commission also concludes that the operation phase risk exposure of investors in the Northern Border segment is lower than the risk exposure of investors in the Alaska segment. The environmental and other risk-increasing factors pertinent to the Alaska segment are not as important here. The major risk imposed on investors by the tariff is that the return on equity or the return of equity may be reduced because of service interruptions.

The Northern Border system will be located in an area which is geologically more stable and readily accessible for any repair work which might be required. Along most

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63/ (Footnote cont'd).

prevailing in 1975, as Hass did. Finally, Staff's downward adjustment of its derived 3.9% equity risk premium for the alleged lower risks of the ANGTS project by the same absolute percentage points as reflected in Hass' analysis, rather than by the same relative percentage, is questionable.

Hass also suggested the use of a rate indexed to interest rates, rather than a fixed-rate. Given current uncertainties with regard to inflation and capital market developments, there is undoubtedly some merit to such a proposal, as evidenced by the increasing use of variable or "floating" interest rates for long-term debt instruments. The Commission is aware that certain portions of the financial community are becoming more interested in the concept of indexing. At this point, however, the Commission does not believe that such a mechanism is necessary. Should the project sponsors discover that such a mechanism would facilitate project financing, the sponsors are certainly free to petition the Commission to impose such a condition.

of Northern Border's route, it will traverse areas which are already served by one or more of the major pipeline systems in the lower-48 transmission network. We believe that because of its location, the operating problems of the Northern Border segment will not be significantly greater than for other lower-48 pipelines. Consequently, the cost-of-service tariff, tracking provisions, and rolled-in pricing reduce the risks of this segment below that of the Alaska segment. The Commission finds, therefore, that 13 percent is a reasonable Operation Phase Rate for the Northern Border segment.

#### 4. Project Risk Premium

The Project Risk Premium is added to the Operation Phase Rate to compensate investors for their risk exposure during the construction of the pipeline. The possibility of not completing the pipeline is the major risk faced by investors in the ANGSTS. A key feature of the President's Decision is its emphasis that this risk of non-completion shall be borne by equity investors and other beneficiaries of the project, such as the State of Alaska or the producers at Prudhoe Bay, rather than by gas consumers or the general public through government loan guarantees. <sup>64/</sup> Consequently, the Decision states that charges may be levied on consumers only after the "completion and commissioning of operation of the system." <sup>65/</sup> If the project is abandoned prior to the initiation of service, investors cannot expect to recover their investment through charges on gas consumers.

The sponsors of the Alaskan segment presented a basic approach or methodology for determining these values of the Project Risk Premium in a paper submitted to the Alaskan Delegate on March 7, 1979, and distributed to all

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<sup>64/</sup> Decision at 124.

<sup>65/</sup> Decision at 38.

interested parties. 66/ The Commission adopts the general methodology earlier used by the project sponsors, but disagrees with certain key parameter values. 67/ Use of more appropriate values results in a Commission estimate of the Project Risk Premium substantially lower than the sponsors' estimate. 68/

First, the Commission has assumed a seven-year schedule of testing and construction, beginning in 1978 and ending in 1984, instead of the longer eight-year schedule assumed by the project sponsors. Even a seven-year schedule is significantly greater in length than the schedule that was presented to the President and the Congress as part of the March 1977 cost estimate. That estimate was based on a construction schedule that would be essentially complete by

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66/ A similar but more elaborate methodology was proposed by Hass, Hass Report at 20-40.

67/ Since the project sponsors in their comments make no reference to this methodology nor comment on the Commission's use of this approach, it is not clear whether they still advocate this approach.

68/ The April 6 Notice identified four issues the Commission believes are important in determining the Project Risk Premium and invited comments on these issues. Based on a review of these comments, the Commission has altered its view of the Project Risk Premium in a number of significant respects.

the end of 1981, with some additional work on compressor stations in 1982.

Second, the Commission has based its calculations on the assumption that there is at least a 67 percent chance that the current sponsors will be able to complete the system. In their paper, the sponsors assumed only a 30 to 40 percent probability of completing the system. The Commission's utilization of 67 percent by no means indicates its belief that the odds for completion of the project are two out of three. However, the Commission also cannot accept the sponsors' representation of a one out of three probability of project completion. The assumption chosen here merely makes certain that the Project Risk Premium compensates for a reasonable estimate of non-completion risk. 69/ The Commission believes that the low probability of success assumed by the sponsors contradicts the assurances given to the President and the Congress, at the time of the President's Decision, that this project could be privately financed under the conditions imposed by the Decision. Consequently, the Commission cannot accept the sponsors' assumptions, and does not believe that it is reasonable to allow a large Project Risk Premium on the basis that it is needed to compensate investors for an assumed small chance of successful completion.

Third, in calculating the Project Risk Premium the Commission makes no provision for the possibility that the

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69/ The Commission notes, in this regard, that comments on the reasonableness of the assumptions concerning the probability of project abandonment and construction schedules were sought from the sponsors in the Notice of Proposed Rulemaking (at 26). None were forthcoming.

sponsors could recover part of their investment through charges on existing customers in the event of abandonment. The Commission believes that the President's Decision did not contemplate such charges, and that plans and present decisions should be made on the assumption that cost recovery from rate-paying consumers will not be allowed in case of abandonment. The Commission recognizes, however, that substantial tax savings could accrue to investors in the event of abandonment. The lost investment is a loss for tax purposes and would reduce the tax payments of the project sponsors by an amount approximately equal to one-half of the investment. 70/

Fourth, the project sponsors' paper and the Commission's April 6 Notice assumed substantially different values for the rate of return used to calculate the allowance for the funds used during construction (AFUDC) included as part of the "risk adjusted rate base." 71/ The project sponsors

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70/ The only exception would be if a partner did not have a taxable income larger than the lost investment. Even in this event, loss carry forward provisions would allow the loss to be deducted from past and future income.

71/ The equity AFUDC rate is conceptually quite different from the actual rate the Commission will allow for determining AFUDC and it is used only to derive the theoretical construct of the "risk adjusted rate base".

proposed 15 percent, while the Notice proposed a lower rate of 9.5 percent. 72/ The Commission stated in the Notice that the risk of non-completion was essentially the only risk faced by investors during construction, and that this was compensated for by the "risk adjusted rate base" and the resulting Project Risk Premium. Under this concept, an equity AFUDC rate for calculating the "risk adjusted rate base" should be very low and incorporate no explicit compensation for risk. The Commission used 9.5 percent, which is comparable to the rate obtainable on low risk government securities.

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72/ Staff's arguments in their initial comments recommending a 4.5 percent after-tax risk free equity AFUDC rate in calculating the risk adjusted rate base are not persuasive. Staff Initial Comments at 80. Staff is confused by the fact that the equity investors in the Alaska gas project are themselves likely to be corporations (the sponsor companies) rather than individual stockholders and thus must pay the corporate profits tax on any interest income at a rate of approximately 50 percent. Staff's argument is that a low risk alternative to an equity investment in the Alaska gas project would be an investment in government bonds from which the interest income would be subject to the corporate profits tax rate. This is misleading since the sponsoring companies can best be thought of as intermediaries for their own stockholders. The choice to a stockholder in a sponsor company is to invest in the Alaska project indirectly through the sponsor company or to invest in a low risk government security. From the perspective of a stockholder in a sponsor company, the interest income and the return on equity are both on the same tax basis (after corporate tax but prior to the personal income tax) and are in fact comparable.