National Energy Board | Office national de l'énergie
CANADA

ERRATA

Please note that the English version of the National Energy Board's *RH-2-94 Reasons for Decision dated March 1995* together with *Order TG/TO-I-95* attached therein are corrected as follows:

1. RH-2-94 Reasons for Decision dated March 1995, Chapter 4, section 4.3 "Views of the Board", 4th paragraph (page 31, shall be replaced by the following:

"The adjustment mechanism for the rate of return on common equity will be based on the following calculation. From the test year bond yield forecast calculated above, the Boardwill subtract the bond yield forecast used in the immediately preceding year. This difference will then be multiplied by 0.75 to determine the adjustment to rate of return on common equity. The adjustment will then be added to the rate of return on common equity approved for the preceding test year and rounded .to the nearest 25 basis points to determine the new approved rate of return on common equity for each of the Group 1 pipelines. The Board will then publicly notify each of these pipelines of its new approved rate of return on common equity and direct each company to file new tolls for the coming-test year."

2. Appendix I, Order TG/TO-1-95, paragraph 8 b) (page 36) shall be replaced by the following:

"b) from the bond yield forecast calculated in a) above shall be subtracted the test year bond yield forecast for the immediately preceding test year and the difference shall be multiplied by a factor of 0.75 to determine the adjustment to the rate of return on common equity; and"

NATIONAL ENERGY BOARD

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National Energy Board

Reasons for Decision

TransCanada PipeLines Limited

Westcoast Energy Inc.

Foothills Pipe Lines Ltd.

Alberta Natural Gas Company Ltd

Trans Québec & Maritimes Pipeline Inc.

Interprovincial Pipe Line Inc.

Trans Mountain Pipe Line Company Ltd.

Trans-Northern Pipeline Inc.

RH-2-94

March 1995

Cost of Capital

National Energy Board

Reasons for Decision

In the Matter of

TransCanada PipeLines Limited, Westcoast Energy Inc., Foothills Pipe Lines Ltd., Alberta Natural Gas Company Ltd, Trans Québec & Maritimes Pipeline Inc., Interprovincial Pipe Line Inc., Trans Mountain Pipe Line Company Ltd. and Trans-Northern Pipeline Inc.

Submissions dated 20 June 1994,
17 June 1994, 20 June 1994, 20 June 1994,
20 June 1994, 17 June 1994, 20 June 1994
and 20 June 1994 respectively, as amended,
for 1995

In respect of Cost of Capital

RH-2-94

March 1995

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Abbreviations

A&S	Alberta & Southern Gas Company
Act	*National Energy Board Act* (the)
ADOE	Alberta Department of Energy
ANG	Alberta Natural Gas Company Ltd
ANS	Alaska North Slope
BC Gas	BC Gas Utility Ltd.
Board	National Energy Board (the)
CAPP	Canadian Association of Petroleum Producers
CBRS	Canadian Bond Rating Service Limited
COFI/Methanex/Cominco	Council of Forest Industries of British Columbia, Methanex Corporation and Cominco Ltd.
CPUC	California Public Utilities Commission
DBRS	Dominion Bond Rating Service Limited
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
Foothills	Foothills Pipe Lines Ltd.
FTA	Free Trade Agreement
Gaz Métropolitain	La Société en commandite Gaz Métropolitain
IGUA	Industrial Gas Users Association
IPL	Interprovincial Pipe Line Inc.
LDC	Local Distribution Company
NAFTA	North American Free Trade Agreement
NEB	National Energy Board (the)
NOVA	NOVA Gas Transmission Limited
Ontario	Ministry of Environment and Energy for Ontario
Pan-Alberta	Pan-Alberta Gas Ltd.
PG&E	Pacific Gas & Electric Company
PGT	Pacific Gas Transmission Company
PITCO	Pacific Interstate Transmission Company
Quebec	Le Procureur général du Québec

R/P Ratio	Reserves/Production Ratio
ROE	Rate of Return on Common Equity
SFV	Straight Fixed Variable
TMPL	Trans Mountain Pipe Line Company Ltd.
TNPI	Trans-Northern Pipeline Inc.
TQM	Trans Québec & Maritimes Pipeline Inc.
TransCanada	TransCanada PipeLines Limited
WCSB	Western Canada Sedimentary Basin
Westcoast	Westcoast Energy Inc.

Glossary of Terms

Class 1 Toll Adjustment Application	Class 1 applications permit adjustments to the tolls for an oil pipeline, which are required because of significant changes in throughput and specific throughput-related costs from those approved in the most recent Board Decision.
Class 2 Toll Adjustment Application	Class 2 applications permit adjustments to the revenue requirement and tolls for an oil pipeline, which are required because of any significant changes in the cost of service from that approved in the most recent Board Decision, with the exception of those changes identified as requiring a Class 3 application.
Class 3 Toll Adjustment Application	Class 3 applications are required when an oil pipeline company is applying to change the rate of return on rate base authorized by the Board, the method of calculation of income taxes or the policies or principles approved by the Board at any previous hearing.
Eastern Zone (TransCanada)	This refers to the Eastern toll zone for purposes of determining the toll applicable to any point on the TransCanada system. It includes all points in the Central Delivery area, the Southwestern Delivery area and the Eastern Delivery area.
Eastern Leg (Foothills)	The portion of Foothills from Caroline, Alberta to Monchy, Saskatchewan, consisting of Zone 6 in Alberta and Zone 9 in Saskatchewan.
Western Leg (Foothills)	The portion of Foothills from Caroline, Alberta to Kingsgate, B.C., consisting of Zone 7 in Alberta and Zone 9 in B.C.
full-cycle supply costs	Total cost associated with resource exploitation typically expressed as an average cost per unit of production over the project life. By contrast to half-cycle cost, it includes capital expenditures associated with exploration.
Group 1 Pipelines	Group 1 pipelines consist of the ten major pipelines which are audited by the Board on a regular basis and whose operating results are continuously monitored by the Board.
load factor	The percentage utilization of capacity.

NEB Rules of Practice and Procedure (1987)	NEB Rules which set out the procedures for making applications, representations and complaints to the Board, the conduct of hearings and generally the manner of conducting any business before the Board.
negative salvage	The amount by which the cost of removing an asset from service exceeds the salvage proceeds.
Part IV	The section of the NEB Act which deals with Traffic, Tolls and Tariffs.
Prebuild Section (Foothills)	The portions of the Alaska Natural Gas Transportation System ("ANGTS") which have been prebuilt to transmit natural gas of Canadian origin before the pipeline is placed in service for the transmission of natural gas of Alaskan origin, being all or part of facilities in Zones 6 to 9.
R/P ratio	A ratio which divides the remaining reserves of a basin by the annual production.
Retail Wheeling	The transmission of electricity from a wholesale supplier to a retail customer by a third party.
SFV Toll Design	A toll design whereby all fixed costs are assigned to the monthly demand charge based on contracted capacity and all variable costs are assigned to actual throughput. The equivalent Canadian term is FFV or Full Fixed Variable.
trigger mechanism	The requirement for oil pipelines to file an application for new tolls when it is forecast that ROE for the calendar year will exceed that approved by the Board at the most recent toll hearing by more than two percentage points.
Zones (Westcoast)	For toll calculation purposes, the Westcoast system is divided into five zones (i.e. Raw Gas Transmission Zone, Processing Zone, Transportation North Zone, Transportation South Zone and Alberta Zone).

Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* and the Regulations made thereunder; and

IN THE MATTER OF Directions on Procedure respecting a Public Hearing concerning the Cost of Capital of TransCanada PipeLines Limited, Westcoast Energy Inc., Foothills Pipe Lines Ltd., Alberta Natural Gas Company Ltd, Trans Québec & Maritimes Pipeline Inc., Interprovincial Pipe Line Inc., Trans Mountain Pipe Line Company Ltd. and Trans-Northern Pipeline Inc.; and

IN THE MATTER OF the National Energy Board Hearing Order No. RH-2-94;

HEARD in Calgary, Alberta on 24, 25, 26, 27, 28 and 31 October 1994; 1, 2, 3, 14, 15, 16, 17, 18, 28, 29 and 30 November 1994; and 1, 2, 5, 6, 7, 8, 9, 12, 13, 14, 15 and 20 December 1994.

BEFORE:

R. Priddle	Presiding Member
	Member
C. Bélanger[1]	Member
K.W. Vollman	Member
R.L. Andrew	Member

APPEARANCES:

C.B. Johnson J.M. Murray C.B. Ledingham	TransCanada PipeLines Limited
J. Lutes R. Sirett	Westcoast Energy Inc.
J. Lutes B. Pierce	Foothills Pipe Lines Limited
D.G. Davies R. Graw	Alberta Natural Gas Company Ltd
L.-A. LeClerc R. Heider	Trans Québec & Maritimes Pipeline Inc.
W.M. Moreland M.H. Patterson	Interprovincial Pipe Line Inc.
C.B. Johnson M.W.P. Boyle C.B. Ledingham	Trans Mountain Pipe Line Company Ltd.
J.A. Campion	Trans-Northern Pipeline Inc.

[1] Effective 2 February 1995, C. Bélanger ceased to participate in the RH-2-94 proceeding

L.G. Keough N.J. Schultz	Canadian Association of Petroleum Producers
R.B. Wallace	Council of Forest Industries of British Columbia, Methanex Corporation and Cominco Ltd.
P.C.P. Thompson, Q.C.	Industrial Gas Users Association
S. Trueman A. Kerr	Amoco Canada Petroleum Company Ltd.
E.C. Eddy	BC Gas Utility Ltd.
I.A. Blue, Q.C. D. Parcell	C.W. Amos
R. Moore	Imperial Oil Resources Limited
C.B. Woods	Mobil Oil Canada
N. Mills	NOVA Gas Transmission Limited
C. Hart	PanCanadian Petroleum Limited
S.R. Miller	Petro-Canada Inc.
M.A.K. Muir	ProGas Limited
E.S. Decter	Shell Canada Limited
J.S. Bulger	La société en commandite Gaz Métropolitain
J.T. Horte	Wascana Energy Inc.
P. McCunn-Miller	Alberta Department of Energy
J. Turchin	Ministry of Environment and Energy for Ontario
J. Brisson	Le Procureur général du Québec
P. Noonan C. Beauchemin	Board Counsel

Overview

(Note: This overview is provided for the convenience of the reader and does not constitute part of the Reasons for Decision. For details, the reader is referred to the relevant sections of the Reasons for Decision.)

Rate of Return on Common Equity for the Benchmark Pipeline for the 1995 Test Year

The Board concluded that, for the 1995 test year, a rate of return on common equity of 12.25% is appropriate for the benchmark pipeline. In making this determination, the Board gave primary weight to the equity risk premium technique. The 12.25% determination was based on a finding that 9.25% is a reasonable estimate of the yield on long-term Government of Canada bonds in 1995 and that a reasonable all-inclusive equity risk premium for the benchmark pipeline is 300 basis points.

The Board determined that it is appropriate to apply the benchmark rate of return on common equity to each of the submitting pipelines who have not been otherwise discharged or exempted from this proceeding.

Capital Structure effective 1 January 1995

The Board found that a 30% deemed common equity ratio is appropriate for TransCanada, Foothills, ANG and TQM effective 1 January 1995.

The Board determined that a 35% deemed common equity ratio is appropriate for Westcoast.

The Board concluded that a 45% deemed common equity ratio is appropriate for TMPL.

Adjustment Mechanism and Re-examination of Cost of Capital Beyond 1995

The Board determined that an automatic mechanism to make yearly adjustments to the approved rate of return on common equity is appropriate. The Board's adjustment mechanism, to apply from 1996 onwards, has the following characteristics:

- the test-year bond yield forecast will be the average of the 3-months-out and 12-months-out 10-year Government of Canada forecast published in the previous year's November issue of <u>Consensus Forecasts</u> (Consensus Economics Inc., London, England) plus the actual 10-year to 30-year bond yield spread in October of that year;

- the change in forecast bond yields will be multiplied by a factor of 0.75 to arrive at the adjustment to the rate of return on common equity; and

- the adjusted rate of return on common equity will be rounded to the nearest 25 basis points.

The Board did not set any time limits or interest rate boundaries on the adjustment mechanism or the capital structures determined in this decision.

Chapter 1

Introduction

The Board began setting the cost of capital for the pipelines under its jurisdiction in 1973. Since that time, some pipelines have had their cost of capital reviewed regularly in the context of pipeline-specific toll proceedings. Other pipelines have only occasionally appeared before the Board for a cost of capital examination. This process has given rise to two concerns. Firstly, the Board has noted that evidence submitted by expert financial witnesses has tended to be much the same from one proceeding to the next. While the financial parameters change from year to year, the techniques and interpretations used in making rate of return on common equity recommendations typically do not. This led the Board to consider what potential economies could be realized from the implementation of a formulaic adjustment mechanism for rate of return on common equity.

Secondly, fluctuations in financial markets continue during and between hearings. Rates of return for one toll-making period, which rely on financial market data, can therefore vary across companies simply because different companies' rates of return are set at different times. In order to address this concern, the Board was attracted by the concept of a generic hearing where all pipeline companies would make their cases simultaneously using a consistent set of financial parameters.

On 17 March 1994, the Board issued Hearing Order RH-2-94 setting out its intention to hold a multi-pipeline cost of capital hearing. The Hearing Order directed eight of the Group 1 pipelines, [these pipelines were: Alberta Natural Gas Company Ltd ("ANG"), Foothills Pipe Lines Ltd. ("Foothills"), Interprovincial Pipe Line Inc. ("IPL"), TransCanada PipeLines Limited ("TransCanada"), Trans Mountain Pipe Line Company Ltd. ("TMPL"), Trans-Northern Pipeline Inc. ("TNPI"), Trans Québec & Maritimes Pipeline Inc. ("TQM"), and Westcoast Energy Inc. ("Westcoast")], to file submissions in respect of their cost of capital to be included in tolls commencing 1 January 1995. The Hearing Order indicated that the issues to be considered were, *inter alia*, the following:

a) What is the appropriate capital structure for each of the pipelines being considered in this proceeding?

b) What is the appropriate rate of return on common equity for each of the pipelines being considered in this proceeding? Should the same rate of return on common equity be awarded for all the pipelines?

c) How often should the pipelines' cost of capital be reviewed? What are the specific factors that would trigger a subsequent review of the pipelines' cost of capital?

d) Subsequent to these proceedings, what simplified procedure should be implemented to effect an annual adjustment to the rate of return applicable to the pipelines between cost of capital proceedings?

In setting this matter down for hearing, it was the Board's intention to put in place means of improving the efficacy of the toll setting process for the year 1995 and beyond. The Board expressed the desire to avoid annual hearings on the cost of capital and was of the view that some automatic mechanism to adjust the return on common equity could be the most appropriate way to ensure that this return continued to be fair to all parties, while avoiding the expense of litigating annual or biennial changes in the rate of return. The Board therefore included as an issue in the RH-2-94 proceeding, the design and implementation of a predetermined adjustment mechanism to the rate of return on the common equity component. The Board's objective in this regard was to conduct detailed examinations of the pipelines' cost of capital only when significant changes had occurred in financial markets, business circumstances, or in general economic conditions. The Hearing Order also indicated that matters other than cost of capital would be addressed in the pipelines' individual toll proceedings.

The Hearing Order indicated that pipelines which presented an uncontested settlement acceptable to the Board two weeks prior to the commencement of the hearing, on either their capital structure or their rate of return on equity, would be exempted from having to deal with these matters in the proceeding. Pipelines exempted by virtue of a settlement could still participate as interested parties. On 17 May 1994, the Board held a Pre-Hearing Conference to address procedural matters relating to the oral portion of the hearing.

Prior to the beginning of the hearing, TNPI submitted a settlement which was set down to be spoken to at the commencement of the hearing. After hearing all parties who wished to be heard, the Board accepted the settlement and TNPI was exempted from further participation in the oral phase of the hearing as a pipeline subject to this proceeding. TNPI elected to retain intervenor status for the remainder of the proceeding.

The oral portion of this proceeding was divided into two phases. The first phase addressed the issue of the appropriate rate of return on equity for a benchmark pipeline as well as the matter of a simplified procedure to be implemented to effect an annual adjustment to the rate of return on equity applicable to the pipelines between cost of capital proceedings. The second phase addressed the pipeline-specific cost of capital issues including capital structure and rate of return on equity where a pipeline or intervenor asked for a rate of return on equity that was different from that of a benchmark pipeline. The oral portion of the hearing commenced in Calgary on 24 October 1994 and closed on 20 December 1994, a total of 29 hearing days.

On 1 February 1995, IPL and the Canadian Association of Petroleum Producers ("CAPP") jointly filed a letter requesting that the Board reserve its decision regarding IPL-specific issues pending the Board's review of a proposed multi-year toll settlement between IPL and its shippers. On 17 February, IPL submitted a multi-year toll settlement for approval by the Board.

On 3 March 1995, the Board discharged IPL from the RH-2-94 proceeding. As a result, cost of capital issues related to IPL were delegated to the RH-4-94 Hearing Panel.

Parties should note that, while the Board has evaluated all of the relevant evidence presented in this proceeding, it has chosen in this Decision to summarize the evidence and positions of the parties only to the extent necessary to explain how specific issues were addressed in the decision-making process.

Chapter 2

Rate of Return on Common Equity for the Benchmark Pipeline

2.1 Introduction

The concept of using a benchmark pipeline to determine the rate of return on common equity originated in the RH-2-94 Pre-Hearing Conference. In the context of this proceeding, a benchmark pipeline refers to a hypothetical utility whose overall investment risks are characteristic of a low-risk, high-grade regulated pipeline. The Board's objective was to determine an appropriate rate of return on common equity for a benchmark pipeline and use this as the standard for determining the rate of return on common equity for all of the pipelines subject to this proceeding.

The Board received evidence from six expert witness panels regarding the appropriate rate of return on common equity for a benchmark pipeline. Although the evidence on some aspects of this issue was more extensive than in the past, and some techniques were presented with greater sophistication, no new techniques beyond the comparable earnings, discounted cash flow ("DCF") and equity risk premium methods were advanced for the Board's consideration. A summary of the recommendations put forward by each of the expert witnesses is provided in Table 2-1. Further details on the key parameters used in arriving at each determination are set out in Appendix II.

Table 2-1
Summary of Recommendations on Fair Rate of Return on Common Equity
(%)

	TransCanada, Westcoast, Foothills & ANG	IPL & TMPL	TQM	CAPP	Ontario & IGUA	COFI/Methanex/ Cominco
Comparable Earnings						
Test Results	11.50-12.00	12.25-12.75	11.53	NA	10.65-11.15	NA
Weight	15	25	equal	NA	40	NA
Discounted Cash Flow						
Fair Rate of Return	12.25	12.50-12.90	10.81-12.56	10.33	9.40-10.75	NA
Weight	10	5	equal	50	20	NA
Equity Risk Premium						
Fair Rate of Return	13.10-13.70	13.30-14.00	13.35-13.98	10.28-10.39	10.20-11.65	11.00-11.50
Weight	75	70	equal	50	40	exclusive
Recommendation	13.00	13.00-13.50	13.00	10.50-11.00	10.75-11.25	11.00-11.50

2.2 Comparable Earnings Technique

Four of the six expert witness panels gave some weight to the comparable earnings technique. Dr. Sherwin and Ms. McShane, on behalf of TransCanada, Westcoast, Foothills and ANG, Dr. Morin, on behalf of TQM, and Dr. Evans, on behalf of IPL and TMPL, all supported the comparable earnings test in principle. Each of these panels, however, noted some shortcomings of this technique and, consequently, gave this test relatively less weight. The shortcomings included inherent weaknesses in the use of this technique, such as reliance on accounting rather than market data. Another shortcoming was the fact that the economic recession and continuing corporate restructuring have caused, and are likely to continue to cause Canadian industrial companies to experience depressed earnings, making the test's results unreliable. Dr. Cannon, on behalf of the Ministry of Environment and Energy for Ontario ("Ontario") and the Industrial Gas Users Association ("IGUA"), relied heavily on the results of the comparable earnings test since he viewed it as less susceptible to interest rate volatility.

The two remaining expert witness panels did not support or rely upon the comparable earnings methodology. Drs. Booth and Berkowitz, on behalf of CAPP, did not rely on the comparable earnings test since they viewed it as useful in providing only a broad macroeconomic check on the fair rate of return on common equity. They also suggested that the comparable earnings test is very sensitive to the sample selection screens. Dr. Waters, on behalf of Council of Forest Industries of British Columbia, Methanex Corporation and Cominco Ltd. ("COFI/Methanex/Cominco"), opposed the use of the comparable earnings test because he viewed accounting returns as an unsuitable basis for calculating investors' required rate of return on common equity.

2.3 Discounted Cash Flow Technique

The DCF test was given some weight by all witnesses except Dr. Waters. Dr. Morin and Drs. Booth and Berkowitz relied on the DCF test to a greater extent than other witnesses. In justifying the weight given to his DCF test, Dr. Morin stated that no one individual method provided an exclusive foolproof formula for determining a fair rate of return but each method provided useful evidence and facilitated the formulation of an informed judgment. Although Dr. Sherwin and Ms. McShane gave relatively little weight to their DCF test results, they utilized the DCF framework in one of their two equity risk premium tests.

While not questioning the theoretical underpinnings of the DCF model, several parties drew the Board's attention to practical limitations of applying the test to industry and utility data. For example, Dr. Sherwin and Ms. McShane pointed to the difficulty of estimating investors' expectations for dividend growth rates. Their concern was echoed by Dr. Waters who stated that it was doubtful that historical growth rates, as applied by most rate of return analysts, could play a meaningful role in cost of capital estimation at this time. Dr. Cannon expressed his concern over the DCF test's reliance on share price information. He stated that sometimes a utility's share price may be elevated or depressed by unreasonable expectations or fears, making the DCF test, in his view, an inappropriate guide for establishing a regulated rate of return.

2.4 Equity Risk Premium Technique

Most expert witnesses gave primary weight to the results of the equity risk premium test in recommending a fair rate of return on common equity for 1995. In forecasting long-term Government of Canada bond yields for 1995, witnesses had regard to the published forecasts of short and long-term interest rates for 1995, spot interest rates in Canada and the U.S., the state of the Canadian and U.S.

economies, the Canadian political situation, expected inflation and economic growth for 1995 and beyond and their own professional judgment. Based on these considerations, witnesses put forward long-term Government of Canada bond yield forecasts for 1995 ranging between 8.00 and 9.25%.

With the exception of Dr. Cannon, all witnesses revised their long-term bond yield forecasts upwards by 25 to 75 basis points, at the beginning of the hearing, as spot and forecast interest rates had moved higher. Dr. Cannon's forecasted long-term bond yield of 8.0 to 8.5% for 1995 was the lowest, while Dr. Morin's forecast of 9.25% was the highest. During the proceeding, Dr. Cannon was challenged about the appropriateness of relying on a long-term bond yield forecast of 8.0 to 8.5% given that, in the months preceding the hearing, spot and forecast interest rates had materially increased. Dr. Cannon took the view that nothing had changed in the financial markets to warrant an upward revision to his long-term bond yield forecast since the filing of his evidence. Dr. Sherwin and Ms. McShane and Dr. Evans relied on a forecasted long-term bond yield of 8.5 to 9.0% for 1995 (mid-point of 8.75%), while Dr. Waters and Drs. Booth and Berkowitz relied on a range of 8.25 to 8.75% (mid-point of 8.50%).

Risk premium estimates for the market as a whole varied in the range of 3.50 to 6.90%. The market risk premiums estimated by the intervenors' witnesses were lower than those of the pipelines' witnesses. One factor contributing to this variance was the fact that Dr. Cannon and Drs. Booth and Berkowitz reduced their historical market risk premiums by 80 to 125 basis points to account for a "purchasing power" or "maturity risk" premium which, in their view, is currently incorporated in the nominal long-term Canada bond yields. In their view, this premium is required by bond investors to account for unanticipated inflation which may affect their ultimate rate of return. Dr. Waters agreed with the concept in principle but did not explicitly make such an adjustment. The pipelines' witnesses did not share the view that such an adjustment was necessary. On the other hand, the pipelines' witnesses gave weight to U.S. market data which tend to increase their market risk premium.

There was little consensus amongst the parties on the relative risk of the benchmark pipeline vis-à-vis the market as a whole. Along with other risk factors, some experts relied on their own calculated betas. Others made use of published betas to estimate the relative risk of the benchmark utility. Some of the experts applied qualitative factors to adjust the market risk premium for the lower risk of utilities. As a result, the relative risk of the benchmark pipeline to the market as a whole was estimated in the range of 45 to 70%.

Some parties presented evidence to justify a financing flexibility allowance adjustment to the "bare-bones" cost of equity. The reasons given for the allowance included out-of-pocket issuance expenses, market pressure and market breaks. The recommended financing flexibility allowance adjustment ranged between 20 and 125 basis points. On the other hand, some of the witnesses argued that there was no need for an explicit adjustment for financing flexibility.

2.5 Views of the Board

The Board is persuaded that the 1990/1991 economic recession and continuing corporate restructuring in Canada may be adversely affecting corporate profitability. As a result, the comparable earnings test may be currently producing results which do not provide an appropriate basis for estimating a fair rate of return for the benchmark pipeline for 1995. The Board is of the view that, under different economic circumstances, the results of this test may be more useful but it assigns little weight to its results in this proceeding.

The Board agrees with the majority of expert witnesses that the DCF test is theoretically sound, but that its usefulness is limited because of certain practical difficulties. The Board shares the views of those who pointed out the difficulty of estimating investors' expected dividend growth rate under the recent and prevailing financial market conditions. The Board notes that Drs. Booth and Berkowitz appear to have taken the greatest amount of care in addressing the practical problems of the DCF test. Notwithstanding their diligence and the comprehensiveness of their DCF analysis, the Board has assigned little weight to the DCF test results in this proceeding primarily because of concerns relating to the lack of objective measurements of investor dividend growth expectations.

Given the problems associated with the application of the comparable earnings and DCF tests at this time, the Board has decided to give primary weight to the results of the equity risk premium test. In arriving at an appropriate long-term Government of Canada bond rate for 1995, the Board took into account short- and long-term spot interest rates and interest rate forecasts for 1995 published in the fall of 1994. In addition, the Board is of the view that inflationary expectations in the U.S. are likely to put upward pressure on U.S. interest rates. This, in turn, is likely to exert upward pressure on Canadian interest rates. Therefore, the Board is of the view that interest rates in Canada during 1995 may not come down to levels forecast by some parties in this proceeding. These considerations have led the Board to rely on the upper end of the recommended long-term Government of Canada bond yield forecast range, namely, 9.25% for 1995.

The Board is of the view that the equity risk premium for the market as a whole is 450 to 500 basis points. In arriving at this conclusion, the Board gives some weight to the concept of "purchasing power risk" or "maturity risk", but acknowledges that specific quantification of this factor is lacking. The Board gave relatively less weight to the U.S. equity risk premium data than to the equivalent Canadian data. After adjusting for the relatively lower risk of the benchmark pipeline and adding a modest allowance for financial flexibility (which includes flotation costs), the Board is of the view that a reasonable all-inclusive equity risk premium for the benchmark pipeline would be 300 basis points. When added to a long-term bond rate of 9.25%, the Board finds that the appropriate rate of return on common equity for the benchmark pipeline is 12.25%.

The Board is of the view that the rate of return on common equity for the benchmark pipeline is appropriate for all of the pipelines subject to this proceeding. The Board is cognizant of the linkage between the rate of return on common equity and the pipelines' capital structures and has determined that any risk differentials between the pipelines can best be accounted for through adjustments to the common equity ratios rather than by making company-specific adjustments to the benchmark pipeline's rate of return on common equity.

Decision

The Board approves a rate of return on common equity of 12.25% for each of the submitting pipelines who have not been otherwise discharged or exempted from this proceeding for the 1995 test year.

Chapter 3

Capital Structure

3.1 Introduction

A summary of existing, applied-for and recommended capital structures is shown in Table 3.1.

Table 3-1
Pipeline Common Equity Ratios
Existing, Applied-for and Recommended by Intervenors

	TransCanada	Westcoast	Foothills	ANG	TQM	IPL	TMPL
Existing							
Common	30%	35%	28%	30%	25%	45%	47.5%
Preferred	9.13%	2.28%	-	-	-	-	-
Applied-for							
Common	30%	35%	30-35%	35%	35%	45-50%	50%
Preferred	9.96%	1.61%	-	-	-	-	-
Recommended by Intervenors (Common)							
CAPP	28%	30%	25%	25%	25%	32%	35%
COFI/Methanex/ Cominco	NA	25-28%	NA	NA	NA	NA	NA
Ontario	27%	35%	28%	30%	24%	NA	NA
IGUA	27%	NA	NA	NA	NA	NA	NA
ADOE	28%	30%	25%	30%	25%	32%	35%
Quebec	30%	NA	NA	NA	25%	NA	NA

The evidence on the appropriate capital structure which was filed by the pipelines subject to this proceeding and intervenors reflected the Board's filing requirements. The discussion centred around the various aspects of business risk, the need for financing flexibility and the issue of cross-subsidization.

3.2 Positions of the Pipelines

3.2.1 Gas Pipelines

The evidence from the gas pipelines indicated a consensus that the Western Canada Sedimentary Basin ("WCSB") is well endowed with natural gas resources and that it will prove to be a prolific supply basin well into the next century. The gas pipelines recognized that, in recent years, supply risks have not been a significant factor. However, some pipelines offered the view that the physical existence of an abundant resource does not necessarily imply that this potential supply will become available to them. Any assessment of the risk profile, they argued, must recognize the possibility of adverse fundamental changes in the political, regulatory and pricing environment and their potentially harmful effects on gas availability and access to supply.

The gas pipelines were also in general agreement that recent reductions in reserves to production ("R/P") ratios are not indicative of an imminent supply shortfall but, rather, reflect the fact that producers are no longer required to maintain excessive inventory. In the same context, TransCanada asserted that with the decline in the reserve life index, the cost of replacing produced gas is approaching the full-cycle cost which would tend to eliminate Canadian producers' competitive edge over most U.S. producers. Westcoast added that the supply cost advantage alone does not guarantee a dominance in the market, as Canadian gas faces a transportation cost disadvantage in getting to most U.S. markets.

TransCanada

TransCanada submitted that, while currently relatively low, its market risk continues to increase. The Company argued that the factors which contribute to that increase in risk are: the growing competitive pressures facing it and its shippers; its renewal policy; the deregulation of gas prices; and open access transportation.

TransCanada submitted that Canadian and U.S. gas markets are becoming increasingly more integrated and competitive. TransCanada noted that it can no longer be viewed as a monopoly with respect to deliveries to eastern Canadian markets since it faces increased competition from alternative pipelines and supplies, including U.S.-sourced supply. TransCanada pointed out that eastern Canadian local distribution companies ("LDCs") are diversifying their gas supply portfolios to include, in some cases, up to 30% U.S.-supplied gas and are proposing new pipeline facilities to connect their franchise areas with U.S. supply and storage facilities.

TransCanada argued that, in its export markets which have increased from 22% of total deliveries in 1985 to approximately 50% in 1994, U.S. gas pipelines have lower firm service tolls which they are further able to discount. In addition, the development of a secondary market for pipeline capacity in the U.S. will mean increased competition for Canadian pipelines and Canadian gas exporters. TransCanada noted that, in the U.S. Northeast, it assumes the risk of shipping gas to an electric generation market which is facing the risks associated with surplus generating capacity, retail wheeling, and the resulting buy-out or buy-down of the power purchase contracts by electric utilities.

In addition, TransCanada noted that while U.S. LDCs have pursued supply portfolio diversification away from traditional U.S. pipeline suppliers by importing Canadian-sourced gas, those diversifications have been largely completed and there is less interest in providing competition to U.S. suppliers (i.e. less interest in Canadian gas imports).

TransCanada submitted that the competitiveness of Canadian gas exports has been put at risk by such regulatory initiatives as incremental tolling, the California Public Utilities Commission's ("CPUC") cross-over ban on the systems of Pacific Gas Transmission ("PGT") and Pacific Gas & Electric ("PG&E") and coal seam subsidies. TransCanada indicated that implementation of Federal Energy Regulatory Commission ("FERC") Order 636 has meant that, instead of contracting with creditworthy downstream U.S. pipelines, it is dealing with replacement shippers who might not be as creditworthy, thus exposing TransCanada to additional risk.

In both its domestic and export markets, TransCanada noted that it faces increased competition from alternative fuels, notably fuel oil in dual-fired boiler applications, if and as the price of those fuels falls below the price of gas on a heat-content basis.

TransCanada pointed out that its existing renewal notice policy gives its shippers the right to evergreen expiring service agreements for a minimum term of one year upon six months' notice. TransCanada argued that while this policy minimizes the shippers' financial exposure and guarantees those shippers access to long-term service, it increases TransCanada's risk of capacity underutilization and cost under-recovery, both of which could result in higher tolls to the remaining shippers and reduce TransCanada's competitive position. TransCanada is forecasting that the average term of firm transportation contracts will fall from eight years in 1994 to four years by the year 2000.

TransCanada argued that, unlike many U.S. pipelines, it has only one supply basin to draw on given that the frontier basins are expected to remain beyond economic reach. While TransCanada relies on the WCSB, the basin is not captive to TransCanada and this poses some risk. Further, the resulting perception that Canadian gas may not be reliable may represent increased risk to TransCanada.

TransCanada submitted that it views the Board's method of regulation to be a fair one, particularly the use of deferral accounts. TransCanada believes that its current regulatory risk is acceptable. TransCanada is, however, of the view that the subject proceeding increases its risk since it may result in TransCanada earning a rate of return on common equity for a number of years which it deems inappropriate. TransCanada believes that the interest in alternate forms of regulation (incentive regulation), the lack of a definitive policy on negative salvage, and the continued challenges to its use of deferral accounts, exposes it to increased regulatory risk.

TransCanada viewed the Free Trade Agreement ("FTA") and the North American Free Trade Agreement ("NAFTA") as developments which should solidify the competitive environment in the North American energy market. TransCanada argued, however, that while these Agreements should provide counter measures against protectionist forces in both Canada and in the U.S., and against federal interference with competitive pricing, constraints imposed by state regulators can negatively affect the competitiveness of Canadian exports. TransCanada submitted that while these agreements enhance assurance that U.S. markets will remain open, they also provide unlimited opportunity for U.S. pipelines to compete in Eastern Canadian markets, thus putting TransCanada at greater risk.

Mr. Lackenbauer, on behalf of TransCanada, indicated that it is of paramount importance that TransCanada maintain a rating in the A category if it is to finance its capital program on reasonable terms. The ongoing financing needs of TransCanada's transmission operations and the degree to which its securities are already largely held by virtually all the major institutions in Canada, would mean that a credit rating of less than A would immediately increase the Company's cost of capital significantly. Mr. Lackenbauer stated that many Canadian institutional investors simply cannot buy debt with a rating below the A category. Of those that can buy BBB rated debt, their capacity to do so is significantly less than that which they have to purchase in the A category or above.

TransCanada emphasized the importance of maintaining its financing flexibility through an optimal capital structure which it believes to be 60% debt, 30% common equity and 10% preferred shares. TransCanada recognized that preferred shares are a more expensive form of financing than debt. However, TransCanada suggested that the replacement of preferred shares by debt is unacceptable.

Mr. Lackenbauer stated that the perception in financial markets is that TransCanada's business risks have not decreased in recent years. Accordingly, any reduction in TransCanada's deemed common equity ratio, given the current consolidated capital structure which provides ample equity to avoid cross-subsidization, would be viewed as a negative shift in the regulatory principles that have been consistently followed by the Board. From a market perspective, it would appear to be a clear case of "entrapment" of investors if the common equity ratio were decreased at this point.

Dr. Sherwin and Ms. McShane regard TransCanada's existing capital structure as bordering on sub-optimal. In their view, 30% common equity lies at an irreducible minimum level in light of the Company's rising business risks. Further, access to capital markets would be impaired in the event of a credit downgrading.

Westcoast

Westcoast stated that the operating and physical components were the most significant negative factors in its overall risk profile. Furthermore, Westcoast stated that any evaluation of its business risks must have particular regard to the fact that over half of its rate base is invested in raw gas transmission and processing facilities. The business risks associated with the ownership and operation of such facilities, particularly the operating and physical, forecasting and supply components, are clearly greater than those associated with the ownership and operation of residue gas transmission facilities alone.

Westcoast noted that it faces increased risk associated with: more stringent environmental regulation affecting the exploration and production of gas; the construction and operation of its pipeline and processing facilities; and the consumption of hydrocarbons. Westcoast further claimed that sections of its supply areas have recently been designated by the B.C. Government as potential wilderness areas. If all these areas were designated protected wilderness areas, 5 to 15 Tcf of undiscovered marketable gas could become inaccessible.

Westcoast indicated that its most significant regulatory and political risks relate to the fact that over 50% of its throughput is shipped to the export market. Westcoast argued that U.S. federal and state governments and regulators will make decisions which are in the best interests of the U.S. and not necessarily those of Canada and Westcoast.

Westcoast indicated that its export market is inherently riskier than its domestic market due to greater gas-on-gas competition. Westcoast explained that this competition is high because the export market has access to gas from the Rocky Mountain and San Juan basins via the Northwest Pipeline system, as well as increased access to Alberta-sourced gas via the PGT system. Westcoast argued that continued excess pipeline capacity to California will result in increased competition in the U.S. Pacific Northwest. In addition, Westcoast stated that the U.S. Pacific Northwest will continue to experience significant interfuel competition, particularly from fuel oil, if current low world oil prices continue.

In its domestic market, Westcoast faces increased competition from other supply sources and from other operators providing the gathering and transmission services directly to producers. Westcoast noted that BC Gas Utility Ltd. ("BC Gas") is continuing its efforts to diversify its gas supply portfolio by increasing its reliance on Alberta and U.S.-sourced gas, thus by-passing Westcoast's raw gas transmission and processing facilities and, in part, its mainline facilities.

Westcoast noted that approximately one-third of the currently contracted firm service to the Huntingdon export point expires in 1996, with an additional one-third expiring in 1997. Westcoast submitted that the automatic renewal rights provisions in its tariff provides shippers with a perpetual renewal option while the risk of non-renewal falls on the remaining shippers and Westcoast. Westcoast pointed out that, based on current depreciation rates, the average economic life of its assets is approximately 45 years. In the absence of long-term service agreements with creditworthy shippers, Westcoast stated that it is exposed to the longer-term risk that gas markets will not exist to enable it to recover its cost of service. Westcoast expects, however, that in the absence of adverse economic, political and regulatory events, most of its transportation service agreements will be renewed.

Westcoast stated that it faces higher total business risks than TransCanada mainly because of the operating risks arising out of the physical differences between the two systems and its lack of market diversity.

Westcoast stated that the appropriateness of the 35% common equity ratio and the resulting capital structure can be assessed by reference to the fact that it has been able to access capital on reasonable terms. Westcoast suggested that the willingness of investors to provide capital is evidence that the deemed common equity ratio and the resulting capital structure is appropriate. In Dr. Sherwin's view, Westcoast's deemed common equity ratio of 35%, which was first approved by the Board in November 1980 and confirmed by the Board in April 1994, continues to be the minimum acceptable common equity component for Westcoast's utility operations.

In the Company's view, the preferred shares should not be removed from the capital structure until such time they are redeemed or retracted. Westcoast suggested that it is unlikely that it would further allocate preferred shares to utility operations given the hybrid nature of these financial instruments and its tax position.

With respect to the issue of cross-subsidization and the actual amount of equity available to support Westcoast's non-NEB-regulated utilities, Westcoast suggested that there are no grounds for concern. Due to the nature of Westcoast's business activities and corporate structure, consolidated financial statements do not meaningfully depict the economic and financial realities underlying Westcoast's corporate activities and financial position. The non-consolidated financial statements, which reflect Westcoast's investment in its subsidiaries and the debt for which Westcoast is liable, more appropriately reflect the economic and legal obligations of Westcoast. Accordingly, Westcoast concluded that no cross-subsidization of its other investments by its NEB-regulated utility activities is taking place.

Foothills

Foothills stated that 90% of the gas shipped on its system is delivered to the highly competitive U.S. Midwest, U.S. Pacific Northwest and California export markets.

Foothills noted that its export markets are short-term or spot in nature, and are subject to competition from other gas sources, from alternative fuels and from other pipelines. Foothills also indicated that the ability of its shippers to move beyond those market areas, particularly beyond the U.S. Midwest, is constrained by Foothills' relatively high tolls and the operational complexity associated with delivering gas through a series of other pipelines.

Foothills submitted that in the U.S. Midwest market, total pipeline capacity utilization is not expected to exceed 60% over the next three to five years due to relatively weak demand growth which will, in turn, result in weaker gas prices and increased competition. With respect to the California market, Foothills suggested that its shippers will continue to be exposed to the risks associated with excess pipeline capacity and the low load factors of competing pipelines serving that market.

Foothills indicated that it is exposed to the risk associated with the fact that 82% of its transportation service contracts expire between 2001 and 2004. For its system as a whole, those firm contracts cover only 36% of Foothills' remaining investment. Under Foothills' tariff, shippers have the automatic right to renew those contracts for a one-year term upon six months' notice. Foothills argued that those contracts should not be viewed as being long term given that its assets are being depreciated over 33 years. Foothills similarly argued that, given the market's trend towards short-term arrangements, there is no assurance that its shippers will continue to serve the aforementioned markets over the medium and long terms.

Foothills asserted that, despite abundant resources in the WCSB, it faces a long-term risk related to gas supply. In a deregulated market, Foothills stated that pipelines with the highest-value markets and lowest costs will be more successful in retaining their gas supply.

Foothills stated that because of its strong reliance on export markets, it is exposed to a high degree of regulatory and political risk. Foothills cited the gas sales contract between Pan-Alberta Gas Ltd. ("Pan-Alberta") and Pacific Interstate Transmission Company ("PITCO") as an example of such risks. This contract is being restructured as a result of the intervention of the CPUC and this could result in a significant reduction in the Pan-Alberta to PITCO sales contract volumes.

Foothills submitted that it faces greater market risk than TransCanada. Specifically, Foothills noted that it has fewer long-term sales contracts supporting its transportation service contracts than TransCanada and that it is essentially an export pipeline. Foothills believes that its U.S. Midwest and California markets face greater pipeline-on-pipeline and gas-on-gas competition than TransCanada faces in its U.S. Northeast markets. Foothills noted that its relatively high transportation costs make it less competitive than other pipelines serving that market. The Company added that it is at greater risk than TransCanada because it operates as a single looped pipeline.

Foothills pointed out that various FERC orders, including FERC Order 636, have resulted in the restructuring and renegotiation of the original contractual arrangements underpinning the Prebuild financing. The result is that the significant initial credit support no longer exists.

In light of its requirements for outside financing, Foothills claimed that it requires the flexibility to finance its operations in public debt markets so that it is not limited to the requirements and restrictions of commercial bank financing. In addition, Foothills suggested that it should have the same flexibility that other pipelines have to finance its pipeline investments with long-term debt. According to Foothills, the risk profile of its business, reflected in the numerous contract restructurings, has precluded it from refinancing its bank indebtedness in the Canadian bond market.

Ms. McLeod, on behalf of Foothills, stated that credit markets impose certain standards of financial integrity on all borrowers. In Canada, the standard imposed by the credit market participants is, according to Ms. McLeod, the equivalent of a senior debt rating in at least the A rating category from the Canadian Bond Rating Service Limited ("CBRS") and the Dominion Bond Rating Service Limited ("DBRS").

ANG

ANG stated that market and regulatory factors are the two key facets of its business risk. On balance, ANG's lack of diversity of markets and the high competitive and regulatory risks of the California market render ANG's business risks higher than those of TransCanada.

ANG indicated that 5% of its throughput is shipped to the B.C. domestic market and 95% for export, notably to California (80%) and the U.S. Pacific Northwest (15%). ANG noted that while those export markets have experienced growth in recent years, exporters are facing increased gas-on-gas and inter-fuel competition and are having to deal with the consequences of new environmental legislation and the availability of hydro electricity.

Excess pipeline capacity into ANG's export markets is estimated to be 300 MMcfd in the U.S. Pacific Northwest and 1,700 MMcfd in California. ANG added that, while the combined ANG and PGT toll is competitive, U.S. gas pipelines have resorted to rate discounting in an effort to maintain throughput and high load factors.

ANG indicated that, as a result of the dismantling of the corporate affiliations and contractual relationships between Alberta & Southern Gas Company ("A&S") and PG&E, some of the ANG transportation held by A&S was assigned to others. However, most of that capacity remains either unassigned or under-utilized.

ANG noted that its transportation service agreements, which were previously supported by long-term gas sales contracts with very secure gas purchasers (90% of ANG's shipments were by A&S for sale to PG&E), are now supported by shippers and gas purchasers who are less creditworthy and who do not have long-term supply and market arrangements. ANG added that the number of shippers on its system has increased from three to 38 as a result of the A&S contract restructuring and ANG's 1993 expansion. ANG concluded that this restructuring has resulted in less certainty that its facilities will be utilized and the associated demand charges paid.

ANG argued that its other businesses are cross-subsidizing its pipeline business. It asserted that tollpayers receive the benefit of ANG's consolidated debt rating without paying the cost associated with a capital structure which would have permitted the pipeline to have achieved the same cost of debt on a stand-alone basis. ANG raised $110 million in 10-year unsecured debentures at a spread of 105 basis points over long-term Canada bonds. On a stand-alone basis, at a 70% debt ratio and with interest coverage ratios well below two times, the interest cost to ANG would likely have been no less than that achievable by a utility with a BBB rating, or a spread over long-term Canada bonds of 125 to 150 basis points. ANG argued that its capital structure should be altered to reflect the pipeline's business risk profile, its size, its tax position and interest coverage considerations on a stand-alone basis. In ANG's view, failure to do so would be equivalent to an endorsement of reverse cross-subsidization.

ANG noted that approximately 10% of TransCanada's capital structure consists of preferred shares, which raises its total equity component over the 30% deemed by the Board.

TQM

Dr. Morin stated that the two significant factors affecting the viability of TQM are increased political risk and increased competition from alternate energy sources.

TQM noted that it serves a comparatively undiversified service territory which has: limited market growth potential; faces intense competition from fuel oil and electricity; and which includes a volatile industrial customer base. TQM estimated that approximately 28.7 Bcf of gas, or 25% of its current throughput, could be displaced by oil and electricity. TQM, which supplies more than 50% of the gas consumed in Quebec, indicated that it has recently experienced lower pipeline throughput due to a poor economic climate and an increase in the price of gas relative to oil.

TQM stated that its future revenues are largely dependent on La Société en commandite Gaz Métropolitain ("Gaz Métropolitain") sales which are concentrated among large-volume, industrial customers tied to the volatile natural resources and commodity economy, namely: metals; pulp and paper; chemical; and manufacturing. TQM noted that these industries have also been vulnerable to plant closures and downsizings and to high gas prices associated with high transportation tolls on the TransCanada and TQM systems.

TQM stated that, being located the furthest from the Alberta natural gas supply source, the Quebec market is encouraged to look at other possible gas supplies and, consequently, other gas supply routes.

TQM, while acknowledging that it generally enjoys fair and reasonable regulatory treatment and that its regulatory risk is, therefore, considered average, submitted that its regulatory risks have increased as a result of deregulation (e.g. gas price deregulation) and greater competition in gas transmission and distribution.

TQM submitted that the political and constitutional uncertainty in Quebec adds to its investment risk. TQM argued that the separation of Quebec could mean the end of the Board's jurisdiction over TQM and result in increasing pressure to set aside the Board's previous decisions regarding TQM's tolls.

Dr. Morin stated that it is important that TQM's common equity ratio be increased from its "anemic" level of 25% in order to preserve flexibility in accessing capital markets on favourable terms. Dr. Morin considers a common equity ratio of 35% to be more reflective of the Company's risk and more beneficial to both the Company and its ratepayers in the long-term.

Based on a comparison of their relative bond ratings, size, interest coverage, common equity ratio, and rate base growth, TQM stated it has higher overall risks than TransCanada.

3.2.2 Oil Pipelines

Dr. Evans indicated that the Board should not adopt CAPP's theory of business risks because the risks associated with the construction and operation of pipeline facilities fall on those who have financed the facilities and whose capital is exposed to the risk of non-recovery or non-compensatory rates of return. Dr. Evans stated that the actions of capital market participants are not consistent with acceptance of the theory that pipeline risks are either diverted or removed entirely.

Dr. Evans indicated that CAPP recommended substantial reductions in the common equity ratios of IPL and TMPL which would sharply increase the financial risks to which these pipelines are exposed and which would increase the investors' required rates of return on common equity.

The oil pipelines expressed a cautious view on oil reserves and the prospective supply outlook. TMPL claimed that crude oil pipelines face an inevitable long term decline in remaining conventional oil reserves from the WCSB. This decline, according to TMPL, will be only partially offset by increased production of high cost synthetic oil and bitumen. In the same vein, IPL observed that its supply risks are now higher than in the 1980s mainly due to the decline in conventional oil reserves in the WCSB.

IPL

IPL identified its primary market risks as: transportation options in origin and destination markets; refinery rationalization; economic activity; conservation; and competition from alternative forms of energy and alternative sources of petroleum.

IPL stated that it faces little competition for deliveries to the Prairie provinces, which account for 13% of its total deliveries. All of the other major centres to which IPL delivers, except Ontario and Buffalo, receive crude oil from other pipelines. In most of these markets, excess incoming pipeline capacity has developed. Most notably in Montreal, Detroit and Toledo, IPL's share of deliveries has dropped significantly over the past 14 years. In Buffalo, IPL's share of the crude oil market remains unchanged at 100% but the size of the crude oil market has fallen 60% due to deliveries from refined products pipelines. In all of IPL's destination markets, the possibility of increased pipeline capacity from other sources threatens IPL's future deliveries. According to IPL, this threat translates into increased competitive risks.

IPL expressed concern that there may come a time when it will not be able to offset revenue losses from declining throughput by raising its tariffs. IPL tried to reflect this risk in its depreciation study but, according to the Company, there are other forecasts that indicate far less supply than was assumed by IPL in estimating the 2020 truncation date. IPL also disputed its alleged monopoly position by stating that it accounts for only 75% of total WCSB oil exports and that there are other pipelines (e.g. TMPL, Rangeland Pipeline Company, Wascana Pipeline Incorporated) delivering crude oil from western Canada to U.S. markets.

IPL identified three factors relating to supply risks, namely, production forecast risks, the long-term production decline, and changes in the product slate.

IPL suggested that it faces political risk due to the reliance of its shippers on export sales of crude oil to the U.S. midwest markets. This risk stems from potential political interference in the supply and demand for crude oil, both domestically and internationally.

Because of regulatory lag, IPL may over-recover or under-recover its costs and allowed rate of return. IPL stated that its ability to reset tolls, via a Class 1, 2 or 3 application or under the 2% trigger mechanism, does not eliminate all risks because the reset tolls are based on a new forecast of throughput and costs. IPL is of the view that the uncertainty it faces in forecasting throughput and costs is not significantly reduced by the method of regulation.

With respect to the issue of cross-subsidization, IPL argued that the common equity available to support the NEB-regulated pipeline reflects actual dollars of common equity invested and not an allocation of equity dollars within a consolidated enterprise.

IPL requested the Board to approve a common equity ratio range of 45 to 50% within which its actual common equity ratio would fluctuate in the years between comprehensive reviews of rate of return and capital structure. Dr. Evans stated that the 45 to 50% range is consistent with the business risks to which IPL is exposed.

TMPL

TMPL indicated that: its business risks have increased since the 1980s; are greater than natural gas pipelines' business risks; are greater than those of IPL; are less than the business risks of TNPI; and are less than those of average unregulated companies. Regarding its market risks, TMPL stated that it faces competition from other transportation modes such as tanker, barge and rail. These alternate modes may transport supplies from the same sources as TMPL or from other sources. In addition, TMPL indicated that these alternate modes do not present shippers with product quality risks.

According to TMPL, the Vancouver market is the most complex of its markets because of the number and types of commodities shipped there, each of which has its own alternative source of supply and means of transportation. This market has been transformed from a primary market for western Canadian crude oil to the swing market for western Canadian refined products. Since two of the refineries closed in 1993, total crude oil deliveries to Vancouver on TMPL have dropped by 17% and a strong export market in refined products has been replaced by increasing product imports.

TMPL stated that its short-term risks are most apparent in relation to the movement of refined products to Vancouver. If there is a refinery upset or a product supply shortfall in Edmonton, shippers will tend to divert the available supply to the landlocked markets while supplying the Vancouver market with marine imports.

The Kamloops market also faces the risks of supply disruptions at the Edmonton refineries which can lower TMPL's delivery volumes. The Kamloops terminals lack the clean-up processing facilities that are available at the Vancouver terminals and, as a result, during the past three summers, shippers transported certain products from Edmonton by rail instead of pipeline.

TMPL stated that exports via the Westridge terminal are affected by the competitiveness of the global oil market. Exports of Canadian crude oil will only be made on a spot basis when better netbacks from traditional markets are not available.

TMPL stated that the B.C. Government is considering the adoption of California's reformulated gasoline specifications. Should this occur, TMPL's risk is considerable if the Edmonton refiners are not configured to produce this quality of gasoline.

With respect to the Washington market, the primary risk relates to the continued competitiveness of Canadian crude oil in relation to Alaska North Slope ("ANS") and offshore sources of supply. The four major refineries located in Washington State which are connected to TMPL are all on tidewater and can source their crude supplies by tanker from virtually anywhere.

TMPL suggested that it faces regulatory risks through its depreciation rates and negative salvage liabilities. Although the regulatory method may be considered just and reasonable at this time, the risk exists that the regulatory regime will change before investments can be recovered. TMPL stated that it faces regulatory risks arising from this proceeding including the frequency of review of the capital structure and ROE, the possibility of a rate of return adjustment mechanism and the implications of these issues for the existing toll adjustment procedures.

According to TMPL, there is no guarantee that, under the current method of regulation, the Company will be able to recover its capital costs in the long run. If market conditions are such that products are not shipped, capital will not be recovered, regardless of the regulatory regime.

TMPL discussed relative risks between oil and gas pipelines and concluded that they are greater for oil pipelines due to such factors as: an earlier projected decline in WCSB supply; greater influence of international factors on supply and prices; vulnerability to refinery closures; greater environmental scrutiny; and the lack of long term transportation contracts or demand charges.

TMPL indicated that its equity base supports the borrowing capacity of the Company allowing the raising of funds by way of debt securities. The size of the equity base is a factor that investors and rating agencies take into account in assessing the security of a company in terms of providing interest coverages which meet the criteria of credit rating agencies. As it is, TMPL does not greatly exceed the key benchmark criteria of $100 million in equity. Furthermore, TMPL is not a frequent issuer of long-term securities and thus does not have the name recognition of some of the larger utilities.

3.3 Positions of Intervenors

3.3.1 CAPP

In formulating its position, CAPP put forth a two-pronged analysis. The first step consisted of categorizing the various business risks identified by the parties subject to this proceeding in a way which permitted, according to CAPP, a more fundamental analysis of these risks. The second prong of CAPP’s dual approach focused on the evolution of the industry and the regulatory environment over time.

CAPP was of the view that the positions presented by the pipelines failed to acknowledge and address the implications and consequences of the existing regulatory and commodity market mechanisms. Based on its conceptual analytical framework, CAPP concluded that the pipelines are shielded from exposure to risks by the regulatory process. Commodity market risk is borne separately by commodity market participants. CAPP concluded that the pipelines are not subject to any meaningful degree of business risks and that, short of an unforseen and unlikely catastrophic event, the pipelines face no serious risks with respect to the return of and on capital.

It is only for any remaining risks that the pipelines should therefore be compensated. In CAPP’s view, these risks are minimal, either because of the remote likelihood of occurrence or because of the small impact they would have on the long-term ability of the pipelines to recover a rate of return of and on capital invested.

In the second part of its analysis, CAPP noted that, as the industry has moved from an administered pricing regime to a deregulated market, there have been gradual changes in many factors which, considered cumulatively, have significantly reduced pipeline business risks. CAPP stated that pipelines are considerably less risky today than they were when their present capital structures were first established. CAPP noted that these changes have yet to be acknowledged in regulatory decisions through downward adjustments to the awarded levels of common equity.

When comparing the business risks of oil pipelines and gas pipelines, CAPP noted that there are no compelling reasons for maintaining the existing significant differential between the deemed equity ratios for the two groups. CAPP suggested that the wide gap has its roots in the historical ownership and evolution of these systems.

With respect to its views on access to capital, CAPP noted that pipeline companies have some flexibility in timing projects and in timing their approach to capital markets. Pipelines have the opportunity to make shorter term financing arrangements if market conditions for the funding of long-term debt are unfavourable at any time. Further, the regulated character of the pipelines gives them the opportunity to seek regulatory relief if prevailing financial market conditions are unfavourable.

According to Drs. Booth and Berkowitz, the requirements for financing flexibility and access to capital markets essentially means that the regulated utility's debt should be rated at least at the investment grade of BBB or better. Therefore, they would recommend that the pipelines increase the use of debt since they have, in general, higher debt ratings than required to maintain their financial integrity.

CAPP suggested that adoption of its recommendations would not result in the pipelines being denied reasonable access to capital markets at reasonable cost. CAPP stated that any potential increase in debt cost will be more than offset by the decrease in the cost of equity. Mr. Cantwell, on behalf of CAPP, indicated that CAPP's recommendations may result in a minor downgrading (one notch) for each of the pipeline companies. Mr. Cantwell stated that in no case would such a downgrade result in ratings which are below investment grade or ratings which would deny the pipeline companies access to the Canadian or U.S. capital markets.

Furthermore, Drs. Booth and Berkowitz stated that, under current market conditions, it is unlikely that a change in bond rating, even should it occur, will have any impact on access to capital. In their view, the cost of debt is determined in the capital market by the normal interaction of supply and demand.

Drs. Booth and Berkowitz noted that preferred shares may have a role to play in the financing of regulated utilities. For those companies which have reached their maximum amount of debt financing, the use of preferred shares is preferable to the use of common equity.

With respect to the level of equity available to underpin the non-NEB-regulated assets of the regulated pipelines, CAPP stated that in the case of Westcoast and IPL, there appears to be explicit subsidization as the non-regulated businesses appear to have substantially lower common equity ratios than their respective regulated businesses.

Gas Pipelines

According to CAPP, no meaningful position has been put forth which challenges the availability of substantial gas reserves from the WCSB. CAPP added that the NEB's estimates of ultimate gas potential increased in each of its last six studies, while the estimates of remaining reserves have remained relatively stable. Based on the NEB's latest supply projections, CAPP concluded that the subject pipelines will be utilized at reasonable levels for their respective economic lives, and that the existing infrastructure may even be insufficient to support the level of demand forecast to the year 2010. According to CAPP, several pipelines have provided evidence on the ample supply of gas from the WCSB in support of recent facilities applications.

CAPP cited the substantial growth in Canadian gas exports and the shippers' willingness to commit to significant new pipeline expansions as evidence of the Canadian gas industry's ability and willingness to successfully compete for gas markets in a deregulated environment. In addition, CAPP stated that the pipelines' market risk has been reduced by: deregulation in Canada which has led to the adoption of market-oriented surplus procedures; deregulation in the U.S. which has culminated in the issuance of FERC Order 636; and the FTA and the NAFTA, which have removed political barriers to trade.

CAPP submitted that the gas pipelines' risks have been reduced by: the inclusion of rate base expansions in rolled-in tolls; the use of the Straight Fixed Variable toll design ("SFV"); the use of diversions and assignments and other means to ensure higher load factors; and the advent of a secondary market for pipeline capacity.

TransCanada

CAPP argued that TransCanada's transportation services are exposed to little competition given: the lack of surplus take-away capacity; the fact that the design of the NOVA system constrains switching between pipelines; the absence of real alternatives to TransCanada's services (which suggests that its short-term service shippers will renew rather than contract with alternate pipelines); and in the diversity of shippers brought about by the new market environment (which has had the effect of reducing the risk of default and non-renewal).

Furthermore, Canadian producers are captive to the pipelines serving the WCSB. Alternative or new pipeline capacity is only available on the basis of a commitment to long-term service agreements, and TransCanada's domestic customers will continue to make only limited use of their access to U.S. transportation and supply due to foreign exchange factors, the complexity of upstream transportation arrangements and the competitiveness of Canadian supply and transportation systems serving domestic markets.

CAPP pointed out that TransCanada acknowledged in its GH-2-94 evidence that the combination of WCSB supply costs and its transportation rates would ensure that TransCanada's system will remain utilized at a reasonable level over the long term.

Westcoast

CAPP argued that Westcoast's market risks are low given its solid and secure shipper and producer base in all four zones. CAPP noted that despite Westcoast's view that it faces increased market risk, B.C. producers continue to seek market access and are willing to support significant facility expansions by executing long-term service agreements. In addition, CAPP suggested that domestic gas deliveries off the Westcoast system will be the preferred supply option over U.S. imports. It added that, while the U.S. Pacific Northwest has become somewhat more competitive, B.C. producers have a transportation advantage over deliveries off the Northwest system. CAPP was confident that B.C. producers would continue to respond to any increased competition.

CAPP quoted a report by the investment firm Smith Barney Shearson, which claimed that the most prolific discoveries in North America are taking place in B.C. where sophisticated exploration is only in the beginning stages, compared with such regions as the southwestern U.S. and Alberta. Westcoast's position as the largest processing and transmission company in B.C. makes it one of the primary beneficiaries of the prolific reserves.

CAPP contended that Westcoast benefits from projects like the Company's proposed Fort St. John and Grizzly Valley Expansion projects in that these will increase the flexibility and diversity of Westcoast's system thereby reducing operating risks.

Foothills

CAPP argued that Foothills has experienced significant transportation service cost reductions and that it is, therefore, well positioned to provide competitive transportation services. CAPP noted that Foothills' Eastern and Western Legs continue to operate at high load factors. CAPP submitted that the cost of service toll methodology continues to allow Foothills to earn its approved rate of rate of return and that the regulatory mechanisms in place shield Foothills from any significant business risks.

Drs. Booth and Berkowitz indicated that Foothills may require improved market access because of the very large amount of refinancing required to convert the syndicated bank financing to traditional bond financing. They suggested that if their proposed capital structure made accessing the bond market difficult, preferred shares could be used in place of some debt, but only on a temporary basis.

ANG

CAPP noted that ANG continues to operate on the basis of 15- and 30-year transportation service contracts with creditworthy shippers, and that the original transportation service agreements formerly held with A&S have been assumed by new shippers for the full 12 years remaining in their term. CAPP also noted that ANG's load factors have steadily improved.

CAPP disagreed with ANG's assessment of the impact of decontracting by pointing out that the Company sought NEB approval for expanded facilities on the basis of unconditional, long-term firm transportation service contracts. No mention was made at that time of any resulting increases in business risk that would warrant a higher deemed equity ratio.

TQM

With respect to TQM's political and regulatory risk, CAPP suggested that, regardless of the political outcome and who ultimately has jurisdiction over TQM, the industry will find a way to compete in Quebec given the importance of this market. However, CAPP assigned a very low probability to the Board changing TQM's regulatory treatment. CAPP submitted that Quebec's political risk is borne by the entire country and that it has existed for some time. CAPP also pointed out that expert witnesses were unanimous in their opinion that the current interest rates already reflect the perceived riskiness associated with the political uncertainty in Quebec.

Oil Pipelines

CAPP stated that access to the U.S. crude oil market is now more secure as a consequence of the FTA. The FTA has: eliminated the potential for crude oil import taxes in the future; provided security for exports; provided protection against disruption of traditional channels of supply; and constrains the United States' use of the national security power as an instrument of U.S. energy policy.

CAPP noted that both IPL and TMPL cite competition in destination markets as increasing business risks. According to CAPP, these pipelines provide the sole link to their respective markets for western Canadian crude oil. Canadian crude oil producers are price takers and have demonstrated an ability to successfully compete in these markets at international prices, adjusted for transportation costs.

CAPP submitted that both IPL and TMPL have recently completed significant expansions which would indicate that Canadian crude oil can, and does, successfully compete in the oil pipelines' respective markets.

CAPP's review of the reserves' estimates of the NEB and the Alberta Energy Resources Conservation Board as well as its own estimates, led to the conclusion that there are substantial volumes of oil reserves to support the existing pipeline infrastructure for the foreseeable future. CAPP maintained that oil supply risks are not a matter of serious dispute, and that this view is corroborated by the pipelines' evidence submitted for recent expansion hearings. These projections imply that IPL and TMPL will continue to be utilized well beyond their current truncation dates.

IPL

CAPP argued that the throughput level on IPL has been totally indifferent to the price of crude oil in spite of IPL asserting that fluctuations in crude prices determine if western Canadian crude oil would be the preferred source of crude by the market. In light of IPL's assertion that the level of crude shipped on its system was a function of refinery demand, CAPP stated that IPL's system has been at capacity notwithstanding the extensive refinery rationalization, which has occurred over a number of years.

High utilization of IPL is currently ensured because it is connected to the best markets for Canadian crude and because the capacities of other Canadian crude oil pipelines are relatively small. Furthermore, IPL bears no financial consequences of reduced supply as long as this is built into its forecast. Even if it is not, IPL can request a Class 1 adjustment when its rate of return on common equity falls more than 2% below the approved level. As for the possible change of the crude oil slate, CAPP demonstrated that it could lead to either under-earning or over-earning. IPL could ask for a toll adjustment if a heavier crude oil slate were to put its rate of return in jeopardy beyond the 2% trigger.

TMPL

CAPP disagreed with TMPL that the change in product mix, the increased reliance on Edmonton refineries and exposure to imports has increased TMPL's risks. The regulatory policies of the NEB protect against these risks by basing tolls on projected throughput, not pipeline capacity.

According to CAPP, TMPL ignored the fact that diversification has allowed the Company to achieve significant growth in rate base, one result being that it is very attractive from an investor's point of view.

CAPP indicated that TMPL has been able to respond to changing market conditions by transporting a variety of products. CAPP stated that TMPL may be exposed to some level of inter-modal competition but that TMPL is essentially a monopoly with respect to the delivery of western Canadian crude oil to the B.C. Lower Mainland and the export markets which it accesses.

CAPP presented a CBRS report which expressed an expectation that TMPL will continue expanding in view of renewed activity in the western Canadian petroleum sector and increased transportation demand from Alberta producers. With respect to TMPL's lower netbacks, CAPP argued that the price of ANS crude is expected to increase with falling Alaskan production, making the Washington State netbacks at least as attractive as those from the U.S. Midwest for Alberta shippers.

3.3.2 COFI/Methanex/Cominco

COFI/Methanex/Cominco's evidence pertained exclusively to Westcoast in the capital structure phase of this hearing. COFI/Methanex/Cominco disputed Westcoast's position that its market risks are significant and argued that whatever risks exist are borne by its shippers and customers and not by

Westcoast. COFI/Methanex/Cominco likewise disputed Westcoast's position that it is exposed to significant risk associated with the number of short-term service agreements because the economics of supply and demand underpinning those service agreements are solid, thus ensuring that the agreements will be renewed.

Dr. Waters, in discussing Westcoast's supply risk, quoted from the Company's 1993 Annual Report. The report stated that gas supply is very robust, particularly in northeastern B.C. which currently has some seven Tcf of established reserves and up to 50 Tcf of ultimate potential reserves. The area is recognized as having some of the largest reserves and highest deliverability per well on the continent. The same report also suggested that the possibility of increased gas deliveries to the east is an opportunity rather than a risk as it would allow greater diversification of Westcoast's gas processing operations and of its markets.

COFI/Methanex/Cominco stated that just and reasonable tolls are typically viewed as tolls which enable a utility to recover its costs, inclusive of a fair rate of return on invested capital. If, in fact, a utility can operate effectively with a lower proportion of common equity, which is the highest-cost form of financing, that ability should be reflected in the rates it charges and not used to enhance shareholder's rates of return. COFI/Methanex/Cominco stated that Westcoast's management must consider the investment risks resulting from a projected common equity ratio in the order of 25% to be acceptable and as not jeopardizing the financial viability of Westcoast Energy Inc., the consolidated entity. COFI/Methanex/Cominco concluded that an equivalent common equity ratio for Westcoast would not result in its investment risks exceeding those of the remainder of Westcoast Energy Inc. Accordingly, it argued that Westcoast's deemed common equity ratio should be lowered. Dr. Waters indicated that his recommended capital structure should not result in a lower debt rating than the current rating.

3.3.3 Ontario/IGUA

Ontario and IGUA co-sponsored Dr. Cannon's evidence for the capital structure phase of this proceeding. Dr. Cannon presented a financial model, described in Section 3.4, which estimated the pipelines' appropriate capital structure.

3.3.4 Other Intervenors

ADOE

The Alberta Department of Energy ("ADOE") argued that TransCanada's overall market risk has declined since deregulation and that the Company enjoys a healthy domestic and export business.

ADOE argued that Foothills' market risk has been reduced by an increase in the number of shippers since these shippers serve more diverse markets. While it concurred that the markets served by Foothills' shippers are underpinned by short-term market arrangements, ADOE argued that the markets themselves are long term and that Foothills' facilities are not at risk of underutilization. ADOE maintained that, while Foothills is subject to some risk because it is an unlooped system, the overall risks are no greater than the risks of the other pipeline systems because they are mitigated by provisions in Foothills' tariff.

ADOE indicated that, with respect to IPL, Canadian producers have no other market options with comparable netbacks and they will, therefore, accept price discounts to displace competing crude supplies and maintain market share in the premium U.S. markets, which IPL serves.

ADOE argued that other transportation services pose no meaningful risk to TMPL’s long-term viability. These transportation modes do not constitute a viable economic alternative to TMPL’s facilities. In reality, these alternatives are basically "relief valves" used to provide a transportation outlet when disruptions in supply or pipeline operations are encountered.

Quebec

Le Procureur général du Québec ("Quebec") argued that TransCanada’s supply risk is minimal. With regard to the risk of a decline in throughput and the resulting increase in tolls, Quebec suggested that the method of regulation currently in place protects the pipelines because shippers are ultimately responsible for the tolls. Quebec added that it did not expect a change in regulation and that there was no point in speculating on alternative regulatory methods.

Quebec argued that it is still too early to draw conclusions on the evolution of TransCanada’s long-term business risk given the recent structural changes in gas markets. Quebec also indicated that TransCanada’s financial risk is minimal.

With regard to TQM, Quebec suggested that the competitiveness of natural gas in the province of Quebec depends on many factors, one of which is the reasonableness of TQM’s tolls. Quebec doubted that an increase in the common equity ratio would translate into an increase in the competitiveness of natural gas in the province. In light of a 37% increase in throughput between 1989 and 1993 and considering the recently-approved crossing of the St. Lawrence River expansion project, Quebec did not agree with TQM’s pessimistic view regarding the province’s natural gas market. Quebec stated that TQM benefits from a stable regulatory environment which is likely to endure.

Finally, Quebec stated that it is not appropriate to speculate about provincial political events and asked that the Board not take this factor into account in its deliberations.

3.4 Relationship between Capital Structure and Cost of Capital

In response to a filing requirement for this proceeding, several parties submitted evidence on the relationship between capital structure and the cost of capital.

Dr. Sherwin and Ms. McShane indicated that, since Canadian regulators have mandated capital structures that are reasonably close to optimal, and since there are few publicly traded utility stocks, there is no Canadian data base for empirical quantification of the impact of changing capital structures on the cost of capital. Accordingly, this forces reliance on theoretical finance models.

Dr. Sherwin and Ms. McShane concluded that the finance models, even when adapted to the real world of Canadian utility regulation, cannot provide the basis for determining a pipeline’s optimal capital structure. The models can, however, test the impact of variables such as: the use of preferred stock; alternative effective income tax rates; and degrees of leverage on the total cost of capital and, hence, the tolls. Their studies suggest that, in an increasingly competitive environment, there should be a shift in the focus of rate of return regulation towards setting an optimal capital structure within a range. For the four gas pipelines (excluding TQM), it is their view that the optimal equity range (including preferred stock) is 35 to 40%, with corresponding debt ratios in the range of 60 to 65%.

Based on the model they believe is appropriate, Drs. Booth and Berkowitz recommended that for each 1% of additional debt financing, the allowed rate of return on common equity should increase by approximately seven basis points. They indicated that this adjustment depends on the firm's initial amount of debt financing, and ranges from a low of four basis points to a high of eight basis points.

Drs. Booth and Berkowitz concluded that these estimates are approximately the increases in ROE required by investors. However, they noted that the estimates are subject to error since they are based upon valuation formulas which are as yet unproven. Moreover, they noted that these formulas ignore the non-tax advantages of debt financing and the effects of financial distress.

Dr. Cannon presented a model to examine the relationship between utility common equity ratios and the corresponding common equity costs in the context of Canadian capital markets. The basis for the model is that the cost of equity is related to deviations in rates of return. The model made the important assumption that only short-run risks need to be considered since long-run risks are not affected by the capital structure.

The results of Dr. Cannon's simulation experiments indicated that there is a "U-shaped" relationship between the weighted average cost of capital and the degree of financial leverage employed. According to Dr. Cannon, this result is not surprising given the very low short-run risks of the pipelines. Since it is short-run risks which are magnified by the use of leverage (lower equity ratio), the very low risks result in only a small magnification of these risks by the use of more debt in place of equity. According to Dr. Cannon's standard deviation of rate of return on common equity analysis, even with a common equity ratio of 22%, TransCanada is less risky than any of his low risk, non-regulated companies.

Dr. Waters indicated that the existence of a number of "real world" factors makes these financial models weak in terms of explaining the relationship between the pipelines' ROE and their common equity ratio. To date, empirical testing to more clearly describe the relationship has not been done successfully.

Dr. Waters concluded that, whenever it is necessary to consider the reality of income taxes, unnecessarily high common equity ratios carry a high cost to the customers in the form of additional taxes. Therefore, Dr. Waters recommended that the common equity ratio be set as low as possible within a reasonable range.

3.5 Views of the Board

3.5.1 General Principles

The Board is of the view that the determination of a pipeline's capital structure starts with an analysis of its business risk. This approach takes root in financial theory and has been supported by the expert witnesses in this hearing. Other factors such as financing requirements, the pipeline's size and its ability to access various financial markets are also given some weight in order to portray, as accurately as possible, a complete picture of the risks facing a pipeline.

The Board has systematically assessed the various risk factors for each of the pipelines but has not found it possible to express, in any quantitative fashion, specific scores or weights to be given to risk factors. The determination of business risk, in our view, must necessarily involve a high degree of judgement, and the analysis is best expressed qualitatively. Under these conditions, we do not consider it realistic to refine the implications for common equity ratios to a precision of, say, one or two percent. The Board recognizes that some parties may see advantages in variations of this magnitude. Nonetheless, the Board does not find it possible or meaningful to seek to determine the required equity ratio with such a degree of precision.

With regard to the argument that regulation shields pipelines from risk, the Board believes that its regulation provides pipelines with a degree of assurance of cost recovery which is absent for non-regulated industrials. However, the Board believes that the realities of market forces cannot be discounted when addressing pipelines' business risks.

Contrary to what some parties advocated during the hearing, the Board is of the view that it is not appropriate to over-leverage a pipeline in order to identify the minimum acceptable deemed common equity ratio acceptable.

3.5.2 Gas Pipelines

In its evaluation of the gas pipelines' business risks, the Board found certain risk factors to be more important than others. With regard to operating risks, the Board views the operation of a single high pressure line and the presence of sour gas gathering pipelines and processing plants as important risk factors. Further, the extent to which a pipeline's markets are diversified, the quality and competitiveness of those markets, and the average length of shippers' contracts were judged to be the most significant factors in the Board's evaluation of market risks. The Board also had regard for the political risk associated with export markets.

There are other risk factors which were examined in these proceedings but which the evidence suggested should be given a lesser weight. These risk factors included the method of regulation under which each pipeline operates and the adequacy of the supply available to it. The Board is of the view that these factors have, at this time, only a marginal impact on the overall risk of pipelines. It assumes the supply risk is approximately equal for all gas pipelines examined in this proceeding.

TransCanada

The Board concludes that TransCanada is a low-risk pipeline and is less risky than unregulated industrial companies. The Board is of the view that TransCanada's risks have not decreased since last evaluated in the context of a toll proceeding.

The Board is of the view that TransCanada's ability to access financial markets on the basis of a 30% deemed common equity ratio over the past 15 years, except for 1982 and 1983 when a common equity ratio of 28% was deemed, is evidence which supports the appropriateness of a 30% deemed common equity for TransCanada at this time.

With respect to preferred shares, the Board concludes that, given current cost rates, it is appropriate for TransCanada to maintain preferred shares in its capital structure at the present time.

Westcoast

Unlike other NEB-regulated pipeline systems which are exclusively residue gas transmission facilities, Westcoast's gathering lines and processing plants account for a significant portion of its overall rate base. The gas transported in Westcoast's gathering systems contains hydrogen sulphide which increases the safety risk and technical complexity of its operation. In addition, three of the five processing plants that Westcoast currently operates are large-scale plants which impose proportionate impacts in case of outages or failures. The Board is of the view that Westcoast's operating and physical risks warrant a higher common equity ratio than that of the other gas pipelines.

The Board is aware that Westcoast's consolidated common equity ratio is projected to be considerably less than the pipeline's 35% deemed level. However, the Board is not convinced that evidence regarding a consolidated equity ratio which is different than a deemed ratio necessarily indicates the existence of cross-subsidization. The Board is of the view that the primary issue is whether or not the financing of the non-jurisdictional assets results in higher debt costs to the NEB-regulated pipeline. Based on the evidence before it, the Board cannot conclude that such cross-subsidization exists in the case of Westcoast.

With respect to preferred shares, the Board concludes that, given current cost rates, it is appropriate for Westcoast to maintain preferred shares in its capital structure at the present time.

Foothills

In reaching its conclusion on the risks facing Foothills, the Board gave weight to the fact that Foothills has a greater reliance on export markets, particularly the highly competitive U.S. Midwest, than other gas pipelines thereby increasing the Company's exposure to regulatory and political risks, and that it operates a high-pressure single-line pipeline.

Against this, the Board has considered Foothills' high degree of assurance of recovering all of its costs through its monthly cost of service method of regulation and the significant portion of its revenues included in the cost of service of other pipelines.

ANG

The Board considered the fact that about 95% of ANG's throughput is destined for export markets and that a significant portion of ANG's throughput is to the California market which is considered to be a competitive market with excess pipeline capacity. However, the Board is of the view that this is balanced by the fact that the California market has been, and is perceived to be, one of the best long-term markets for Canadian gas.

Against these market considerations, the Board took account of ANG's monthly cost of service method of regulation which provides a greater assurance than the forward test year method that the Company will recover its costs and also considered its relatively longer transportation contract terms.

The Board is of the view that the cross-subsidization issue was not of sufficient materiality to warrant a change in ANG's deemed capital structure.

TQM

The Board is of the view that TQM is characterized by its limited market growth opportunities, the intense competition from alternate energy sources and its relatively low load factors. Furthermore, the Board notes that TQM is a single pipeline which exposes it to a relatively higher risk than a pipeline with multiple lines.

On the other hand, the fact that TransCanada is the sole shipper on TQM (making TQM's tolls part of TransCanada's cost of service) dilutes TQM's high unit cost and provides the Company with a high degree of assurance that its costs will be recovered.

3.5.3 Oil Pipelines

With regard to the oil pipelines' business risks, the Board is of the view that the quality and the competitiveness of the markets served by a pipeline are the two most significant factors to be considered in its analysis.

The Board's view on crude oil supply risks is that the resource base, in terms of both the remaining established reserves as well as discovered and undiscovered resources, is sufficiently large and diversified to support the existing pipelines beyond their current truncation dates under most circumstances. In particular, the Board anticipates that a future decline in conventional oil supply from the WCSB will tend to be offset by an increased supply of unconventional oil. This view is corroborated by IPL's and TMPL's evidence contained in recent expansion applications.

The deregulation of crude oil prices and the effective removal of export controls in 1985 has allowed Canadian crude oil prices to fluctuate in accordance with events in North American and international crude oil markets and has facilitated exports to the U.S.

The Board considered that the pipelines are nearly fully utilized, that they have been expanding recently, and that the outlook for WCSB oil supply is more optimistic than when oil pipelines' business risk was previously assessed.

The Board is of the view that the risks faced by the oil pipelines are low compared to industrial companies but greater than the bottom end of the risk spectrum.

In reaching its conclusion on the risks faced by TMPL, the Board took account of risk arising from marine competition. The Board also considered the fact that TMPL is a multi-product pipeline.

Decision

The Board recognizes that the gas pipelines have some individual characteristics, described in its views above, which differentiate one from another. On balance, however, the Board is of the view that the overall business risks of TransCanada, Foothills, ANG and TQM balance out such that a similar common equity ratio can be given to these four pipelines. Accordingly, the Board approves a common equity ratio of 30% for TransCanada, Foothills, ANG and TQM. The Board is of the view that Westcoast is riskier than the other four gas pipelines, and approves a common equity ratio of 35% for Westcoast. The Board also approves the maintenance of preferred shares in TransCanada's and Westcoast's capital structures.

The Board concludes that the appropriate deemed common equity ratio for TMPL is 45%.

Chapter 4

Adjustment Mechanism and Re-examination of Cost of Capital

4.1 Adjustment Mechanism

The recommendations made by the expert witnesses in this proceeding in regard to a simplified procedure for effecting adjustments to the allowed rate of return on common equity are summarized in Table 4-1.

Table 4-1
Summary of Adjustment Mechanism Recommendations

	TransCanada Westcoast, Foothills & ANG	TQM	IPL and TMPL	CAPP	Ontario and IGUA	COFI/Methanex/ Cominco
Bond Yield Forecasting Method	Average of 3-months-out and 12-months-out 10-year Government of Canada bond yield forecasts in the October Consensus Forecasts, plus actual 10- to 30-year spread in third quarter.	Average 30-year Government of Canada bond yields in September, October and November of the current year.	Average of August, September and October 12-months-out and October 3-months-out 10-year bond yield forecasts in Consensus Forecasts plus the actual 10-year to long-term bond spread.	Average of June, August and October 12-months-out and October 3-months-out 10-year bond yield forecasts in Consensus Forecasts plus 25 basis points.	Consensus Forecasts or alternate consensus-based forecast, if available.	Agrees with the mechanism set forth by TransCanada, Westcoast, Foothills and ANG.
Adjustment Factor	One-to-one while bond yields are between 7.0-10.0%, 0.5 outside that range.	0.5 to one.	One-to-one over the bond yield range 7.5-9.5% and 2/3 outside that range.	0.8 to one.	0.75 to one.	0.5 if bond yields are greater than 10%, one-to-one if bond yields are less than 10%.
Minimum Change in Forecast	Plus or minus 25 basis points.				Plus or minus 25 basis points.	Agrees with the mechanism set forth by TransCanada, Westcoast, Foothills and ANG.
Mechanism Boundaries	Bond yields outside the 7.0-12.0% range, a maximum three to five year duration.	Bond yields plus or minus 250 basis points from the current level.		Bond yields of plus or minus 200 basis points from current levels or three years.	Three years.	Agrees with the mechanism set forth by TransCanada, Westcoast, Foothills and ANG.

Dr. Sherwin and Ms. McShane concluded that the only appropriate adjustment mechanism would be one based on the equity risk premium method. Examining the historical relationship between interest rates and risk premiums, they found that for every 1% change in interest rates there was an approximately 0.5% change in the risk premium in the opposite direction. However, because the Board has decreased rates of return in lock step with interest rates in recent years (i.e. 1991 to 1994), these witnesses argued that the adjustment mechanism should allow for symmetrical treatment within some range. With this in mind, Dr. Sherwin and Ms. McShane recommended a mechanism which would adjust the approved rate of return on common equity on a one-to-one basis with changes in forecast interest rates as long as interest rates stayed in the 7.0 to 10.0% range. Outside this range, approved rate of returns would be adjusted by one-half the change in forecast interest rates.

For the forecast of interest rates for the test year, Dr. Sherwin and Ms. McShane recommended using the average of the 3-months-out and 12-months-out 10-year Government of Canada bond yield forecast published in the October Consensus Forecast, plus the actual 10-year to 30-year bond yield spread observed in the third quarter of the current year. This figure would be compared to the interest rate forecast used in the previous year and differences larger than 25 basis points would then be used to determine the change in approved rate of returns. Finally, Dr. Sherwin and Ms. McShane recommended that the mechanism operate for no more than three to five years before a review. However, in the event that long-term Government of Canada bond yields go outside the 7.0 to 12.0% range, they recommended that a hearing to examine the fundamentals of cost of capital should be held.

Dr. Morin recommended that the Board adopt a mechanism that would automatically adjust the approved rate of return on common equity to reflect changes in capital market conditions. This mechanism would be based on the equity risk premium method using the average yield on 30-year Government of Canada bonds in September, October and November as a forecast of the next year's interest rates. The risk premium used would start at 4.0% and be adjusted 50 basis points downwards (upwards) for every 1.0% increase (decrease) in interest rates. A 20 basis point adjustment would be made to the risk premium to account for flotation costs. Dr. Morin recommended that his mechanism operate for three years and within a range of interest rates plus or minus 250 basis points from current levels before being reviewed.

Dr. Evans also recommended using an equity-risk-premium-based adjustment mechanism. This mechanism would rely on an average of the Consensus Forecast's 12-months-out forecasts in August, September and October and the 3-months-out forecast in October of 10-year Government of Canada bond yields plus the spread between 10-year and long-term Government of Canada bonds (using data from the Bank of Canada). Approved rates of return would be adjusted on a one-to-one basis as long as interest rates stay within a 7.5 to 9.5% range and by a factor of two-thirds of the changes in forecast interest rates outside this range.

IPL and TMPL both requested that the Board modify the current toll adjustment procedures for oil and products pipelines. Currently, changes to a company's cost of debt and equity are examined under the Class 3 toll adjustment procedure and normally require an oral hearing. Both companies requested that the Board revise this process so that changes in the cost of debt and changes in the approved rate of return on common equity arising from the adjustment mechanism could be examined in a Class 2 toll adjustment procedure, which would not normally require an oral hearing.

Drs. Booth and Berkowitz recommended that approved rates of return be adjusted each year if the forecast interest rate changes by between 50 and 200 basis points. This forecast would be calculated by averaging the Consensus Forecast's June, August and October 12-months-out and October 3-months-out 10-year bond yield forecast plus a 25 basis point spread. A smaller change would yield no adjustment and a larger change would lead to a new hearing. The adjustment made to the approved rates of return would be 80% of the change in forecast interest rates. The mechanism would stay in place for three years.

Dr. Cannon stated that, although he would prefer to use both the comparable earnings and equity risk premium methods in his adjustment mechanism, he could find no simplified, generally-accepted way of doing so. Therefore, he recommended that the equity risk premium method should be used. For the interest rate forecast, Dr. Cannon recommended using the Consensus Forecast, or another consensus-based forecast, should it be available. If the interest rate forecast for the test year differs from that set at the hearing by more than 25 basis points, Dr. Cannon's mechanism would result in an adjustment to approved rates of return by 75% of the difference. In Dr. Cannon's view, a new hearing to examine cost of capital issues should be held every three years.

Dr. Waters asserted his general agreement with the adjustment mechanism set out by Dr. Sherwin and Ms. McShane. However, he disagreed with using the one-half to one adjustment factor when interest rates are less than 7.0%. Dr. Waters stated that if the market is calling for lower rates of return, regulatory boards should not second guess the market.

Mr. Parcell, on behalf of C.W. Amos, presented his view that no one method could adequately measure the changes in cost of capital over time. His analysis of the relationship between interest rates and rates of return on common equity showed that changes in interest rates were not the only explanatory variable that should be considered. Mr. Parcell recommended that the Board adopt an adjustment mechanism that would require the Board to undertake yearly analyses using a variety of methods to determine the changes in the cost of capital. These studies would then lead to changes in the approved rate of return on common equity for the pipelines under the Board's jurisdiction.

4.2 Re-examination of Cost of Capital

All parties in this hearing held similar views as to the frequency of review of the pipelines' cost of capital. They agreed that if an adjustment mechanism is in place, no hearing to review cost of capital matters would be needed for three to five years, barring unexpected financial market disruptions. IPL suggested that interim reviews should be held only on a complaint basis and provided a list of circumstances that would provide a party with cause to request an interim hearing.

4.3 Views of the Board

Most parties recommended adjustment mechanisms based strictly on the equity risk premium method. However, one witness recommended an adjustment mechanism that would require the Board to conduct studies of the change in the cost of capital based on various methods of cost of capital determination. The Board believes that this latter type of adjustment mechanism is not consistent with the goal of improving the efficacy of the toll setting process, as set out in the hearing order. The Board agrees that an adjustment mechanism based on the equity risk premium method is appropriate. Therefore, the Board has decided to implement a rate of return on common equity adjustment mechanism based on changes in forecast long-term Government of Canada bond yields.

Each year, the Board will determine the bond yield forecast for the coming test year by examining the November issue of Consensus Forecasts (Consensus Economics Inc., London, England). The 3-month-out and 12-month-out forecasts of 10-year Government of Canada bonds will be averaged. To this figure will be added the average spread between 10-year and 30-year Government of Canada bond yields. The Board will calculate this coverage using the 10-year and 30-year Government of Canada bond yields published daily in The Financial Post throughout October of the current year.

The Board is not attracted by the idea of adjusting the approved rate of return on common equity on a one-to-one basis with changes in forecast bond yields. The Board has had regard for the view expressed by several parties that as interest rates change, the risk premium changes. The Board believes that an adjustment mechanism based on this proposition should produce fair results and prove durable during the target period for at least three years. The expert witnesses in this hearing estimated this ratio as between 0.5 to 0.8. The Board finds that an adjustment mechanism using a 0.75 ratio for changes in forecast bond yields is appropriate.

The adjustment mechanism for the rate of return on common equity for the pipelines will be based on the following calculation. Each November, the Board will subtract the bond yield forecast for the coming test year from the bond yield forecast used in the previous test year. The difference in these two forecasts will be multiplied by 0.75, and rounded to the nearest 25 basis points, to determine the change in the approved rate of return on common equity for each of the Group 1 pipelines. The Board will then publicly notify each of these pipelines of its new approved rate of return on common equity and direct each company to file new tolls for the coming test year.

The oil pipelines requested that the Board modify the current toll adjustment procedures so that changes in the cost of debt and changes in the cost of common equity caused by the adjustment mechanism could be dealt with in the context of a Class 2 toll adjustment procedure. It is the view of the Board that toll adjustments that are caused by the rate of return on common equity adjustment mechanism can be implemented outside the Class 1, 2 and 3 toll adjustment procedures set out by the Board in its December 1990 decision. Because the adjustment mechanism has been examined thoroughly in this procedure, toll adjustments arising from this mechanism will not need further examination as they arise. Accordingly, the Board does not find that a formal toll adjustment procedure need be followed when changes in tolls occur due to the operation of the adjustment mechanism. The Board is not convinced that any changes to the Class 2 and 3 toll adjustment procedures need be implemented to take account of the decisions taken in this proceeding.

The following table shows results produced by the adjustment mechanism over an illustrative range of interest rates. The upper and lower interest rate forecasts shown in the table are not intended to indicate boundaries beyond which the adjustment mechanism will not operate.

Table 4-2
Illustrative Results Produced by the Adjustment Mechanism

Interest Rate Forecast	Rate of return on Common Equity	Rounds To Approved Rate of Return	Implied All-In Equity Risk Premium
7.00%	10.56%	10.50%	3.56%
7.50%	10.94%	11.00%	3.44%
8.00%	11.31%	11.25%	3.31%
8.50%	11.69%	11.75%	3.19%
9.00%	12.06%	12.00%	3.06%
9.25%	**12.25%**	**12.25%**	**3.00%**
9.50%	12.44%	12.50%	2.94%
10.00%	12.81%	12.75%	2.81%
10.50%	13.19%	13.25%	2.69%
11.00%	13.56%	13.50%	2.56%
11.50%	13.94%	14.00%	2.44%
12.00%	14.31%	14.25%	2.31%
12.50%	14.69%	14.75%	2.19%
13.00%	15.06%	15.00%	2.06%

The Board expects that this adjustment mechanism will prove robust over a wide range of interest rates. Accordingly, the Board does not find that it is necessary to specify a bond yield range outside of which the mechanism would not operate. The Board is not setting a limit on the life of the mechanism and it does not expect to reassess the rate of return on common equity in a formal hearing for at least three years. The Board has confidence that the adjustment mechanism adopted will provide an appropriate balance between the interests of pipeline company shareholders and those of shippers.

The Board also expects that the capital structure set in this hearing for each of the pipelines will endure for an extended period of years. The Board will be prepared to consider a reassessment of capital structures, likely on an individual basis, in the event of a significant change in business risk, in corporate structure or in corporate financial fundamentals. The Board does not favour routine reassessments of capital structure. For these reasons, the Board has not set out a specific date or any criteria for capital structure re-evaluation. Any reassessment of capital structure, for reasons such as those expressed above, must be at the request of the pipeline itself, its shippers or some other interested party. It would then be for the Board to assess the merits of such a request.

Decision

The Board has decided that, subsequent to the 1995 toll year, allowed rates of return on common equity will be adjusted annually using the equity risk premium technique described above.

The Board has further determined that it is not appropriate to preset time limits or other boundaries for either the adjustment mechanism or the capital structures set out in Chapter 3.

Chapter 5

Disposition

The foregoing chapters, together with Order TG/TO-1-95 constitute our Decisions and Reasons for Decision on this matter.

The Board reserves judgment on all Decisions respecting IPL.

R. Priddle
Presiding Member

K.W. Vollman
Member

A. Côté-Verhaaf
Member

R.L. Andrew
Member

Calgary, Alberta
March 1995

Appendix I

Order TG/TO-1-95

ORDER TG/TO-1-95

> IN THE MATTER OF the National Energy Board Act ("the Act") and the Regulations made thereunder; and
>
> IN THE MATTER OF the RH-2-94 proceeding held pursuant to Part IV of the Act which considered the capital structure effective 1 January 1995 and the rate of return on common equity for the 1995 test year, for all Group 1 pipelines falling under the Board's jurisdiction with the exception of Interprovincial Pipe Line (NW) Ltd. and Cochin Pipeline Ltd. ("the applicant pipelines").

Before the Board on 16 March 1995.

WHEREAS the applicant pipelines filed their submissions with the Board on 20 June 1994, as amended, dealing with cost of capital issues for orders determining the appropriate capital structure and rate of return on common equity that the applicant pipelines could include in their tolls for service rendered commencing 1 January 1995;

AND WHEREAS Trans-Northern Pipelines Inc. ("TNPI") submitted a settlement at the commencement of the oral phase of the hearing which was accepted by the Board after having heard all parties who wished to be heard on it;

AND WHEREAS TNPI was then exempted from any further participation in the proceeding as an applicant pipeline electing, however, to retain intervenor status for the remainder of the proceeding;

AND WHEREAS a public hearing commenced on 24 October 1994 pursuant to Hearing Order RH-2-94, as amended, in the City of Calgary in the Province of Alberta, during which time the Board heard the evidence and arguments presented by the applicant pipelines and all parties;

AND WHEREAS Interprovincial Pipe Line Inc. ("IPL") and the Canadian Association of Petroleum Producers ("CAPP") filed on 1 February 1995 a joint application requesting that the Board reserve the portion of the RH-2-94 decision respecting IPL-specific issues, pending the Board's consideration of a proposed toll settlement;

AND WHEREAS the Board by letter dated 9 February 1995 provided an opportunity for all parties to express their views on the joint application before making a determination on it;

AND WHEREAS the Board, having heard all parties who wished to be heard on this joint request, on 3 March 1995 discharged IPL from Hearing Order RH-2-94 and from any further participation in the proceeding as an applicant pipeline;

AND WHEREAS the Board's decisions on the applicant pipelines' submissions are set out in its Reasons for Decision dated March 1995, and in this Order;

IT IS ORDERED THAT:

1. Alberta Natural Gas Company Ltd ("ANG"), Foothills Pipe Lines Ltd. ("Foothills"), TransCanada PipeLines Inc. ("TransCanada"), Trans Mountain Pipe Line Company Ltd ("TMPL"), Trans Québec & Maritimes Pipeline Inc. ("TQM"), and Westcoast Energy Inc. ("Westcoast") shall for accounting, tollmaking and tariff purposes, implement the decisions outlined in the Reasons for Decisions dated March 1995 and in this Order;

2. ANG shall respect a capital structure of 30% deemed equity ratio effective 1 January 1995 and a rate of return on common equity of 12.25% for the 1995 test year.

3. Foothills shall respect a capital structure of 30% deemed equity ratio effective 1 January 1995 and a rate of return on common equity of 12.25% for the 1995 test year.

4. TransCanada shall respect a capital structure of 30% deemed equity ratio effective 1 January 1995 and a rate of return on common equity of 12.25% for the 1995 test year.

5. TMPL shall respect a capital structure of 45% deemed equity ratio effective 1 January 1995 and a rate of return on common equity of 12.25% for the 1995 test year.

6. TQM shall respect a capital structure of 30% deemed equity ratio effective 1 January 1995 and a rate of return on common equity of 12.25% for the 1995 test year.

7. Westcoast shall respect a capital structure of 35% deemed equity ratio effective 1 January 1995 and a rate of return on common equity of 12.25% for the 1995 test year.

8. The National Energy Board will adjust the rate of return on common equity for each applicant pipeline subject to this order as of the first day of January 1996 and again as of the first day of January in each subsequent calendar year according to the following:

   a) a bond yield forecast for the test year will be derived by calculating the average of the 3 months out and 12 months out 10-year Government of Canada bond yield forecast published in the November issue of Consensus Forecasts (Consensus Economics Inc., London, England) and adding thereto the current 10-year to 30-year Government of Canada bond yield spread derived by calculating the daily average difference between the 10 year and the 30 year Government of Canada bond yields as published in the Financial Post (Financial Post) in the month of October in the current year; and

   b) the bond yield forecast calculated in (a) shall be subtracted from the test year bond yield forecast for the immediately preceding test year and the difference multiplied by a factor of 0.75 to determine the adjustment to rate of return on common equity; and

   c) the product derived in paragraph (b) shall be added to the rate of return on common equity applicable in the preceding test year; and

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d) the sum resulting from paragraph (c) shall be rounded to the nearest 25 basis points.

e) each applicant pipeline shall file a revised tariff of tolls in accordance with the calculation issued by the Board to be effective on the first day of January in each calendar year.

NATIONAL ENERGY BOARD

J. S. Richardson
Secretary

TG/TO-1-95

Appendix II

Table a2-1
Summary of Rate of Return on Common Equity Evidence

Summary of Rate of Return on Common Equity Evidence

Comparable earnings

	Dr. Sherwin & Ms. McShane	Dr. Evans	Dr. Morin	Drs. Booth & Berkowitz	Dr. Cannon	Dr. Waters
Business Cycle	1985 - 1993	1984 - 1993	1983 - 1993		1985 - 1993	
Sample Size	24 Industrials	21-20 Industrials	23 Industrials	n.a.*****	27 Industrials	n.a.*****
Test Results	11.50 - 12.00%	13.50 - 14.00%	11.53%			
Adj. for Lower Risk of Util.	0.00%	-1.25%	0.00%			
Fair Return	**11.50 - 12.00%**	**12.25 - 12.75%**	**11.53%**		**10.65 - 11.15%**	
Weight Assigned	15.00%	25.00%	Equal to all tests		40.00%	

Discounted cash flow

	Dr. Sherwin & Ms. McShane	Dr. Evans	Dr. Morin		Drs. Booth & Berkowitz		Dr. Cannon		Dr. Waters
Sample	24 Industrials	21-20 Industrials	23 Industrials	6 Tel Utilities	12 Utilities	12 Utilities	11 Utilities	27 Industrials	20 Non-Utilities
Dividend Yield	2.50%	2.25%	3.19%	5.74%	5.57 - 5.85%	5.71%	6.0 - 6.2%	2.3 - 2.7%	5.90%
Growth	8.70%	9.00 - 9.75%	9.20%	4.79%	4.52 - 5.50%***	3.83%***	3.0 - 4.0%	7.5 - 7.9%	4.00%
DCF Equity Cost	11.20%	11.25 - 12.00%	12.39%	10.53%	10.09 - 11.35%	9.54%	9.0 - 10.2%	9.8 - 10.6%	9.90%
Adj. for Lower Risk of Util.	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-0.20 - 0.15%	-0.50%	
Bare-bones Cost of Equity	11.20%	11.25 - 12.00%	12.39%	10.53%	10.09 - 11.35%	9.54%	8.8 - 10.05%	9.3 - 10.1%	
DCF ROE for IPL & TMPL		11.50 - 11.75%**							
Flotation or Fin. Flexi Adj	1.05%*	1.00 - 1.15%	0.17%	0.28%			0.60 - 0.65%	0.60 - 0.65%	
Fair Return	**12.25%**	**12.50 - 12.90%**	**12.56%**	**10.81%**	**10.09 -11.35%**	**9.54%**	**9.40 - 10.70%**	**9.9 - 10.75%**	**9.90%**
Weight Assigned	10.00%	5.00%		Equal to all tests	25.00%	25.00%	10.00% weight	10.00% weight	no weight

Equity risk premium

	Dr. Sherwin & Ms. McShane	Dr. Evans	Dr. Morin	Drs. Booth & Berkowitz		Dr. Cannon	Dr. Waters
			Results Combined	Preferreds	Bonds	Results Combined	
Market Risk Premium	5.0 - 5.5%	6.00%	5.9 - 6.9%	-	3.5 - 4.0%****	4.50 - 5.00%****	4.50%
Risk Prem-Benchmark Util.	3.50%			1.83 - 2.53%	1.58 - 2.20%	1.56 - 2.51%	2.25%
"Risk Prem for IPL, TMPL"		3.75%					
Risk Premium for TQM			3.90 - 4.53%				
Long Canada Rate - 1995	8.50 - 9.00%	8.50 - 9.00%	9.25%	7.68 - 8.02%	8.25 - 8.75%	8.00 - 8.50%	8.25 - 8.75%
Bare-bones Cost of Equity	12.0 - 12.50%	12.25 - 12.75%	13.15 - 13.78%	9.51 - 10.55%	9.83 - 10.95%	9.56 - 11.01%	10.50 - 11.0%
Financing Flexibility	1.10 - 1.20%	1.05 - 1.25%	0.20%	Int Adj 0.25%	0.00%	0.60 - 0.65%	0.50%
Fair Return	**13.10 - 13.70%**	**13.30 - 14.0%**	**13.35 - 13.98%**	**9.76 - 10.80%**	**9.83 - 10.95%**	**10.20 - 11.65%**	**11.0 - 11.50%**
Weight Assigned	75.00%	70.00%	Equal to all tests	25.00%	25.00%	40% weight	exclusive reliance
				Mid-pt. 10.28%	Mid-pt. 10.39%		
Overall Recommendation	**13.00%**	**13.00 - 13.50%**	**13.00%**		**10.50-11.00%**	**10.75-11.25%**	**11.0 - 11.50%**
					Emphasis 11.0%		

* Dr. Sherwin and Ms. McShane's implied financing flexibility adjustment.

** Dr. Evans recommends focus on the middle of the bare-bones cost of equity estimate.
*** Drs. Booth & Berkowitz's dividend growth rates calculated as the difference between the final result and the dividend yield.
**** Drs. Booth & Berkowitz's and Dr. Cannon's market risk premium adjusted for purchasing power or maturity risk.
***** Technique not applied.
Note: The numbers in this table have been presented in a consistent fashion and, therefore, may have been derived indirectly from evidence provided in this proceeding.