THE UNIVERSITY OF CALGARY

Effects of Changes in Risk Exposure on Capital Structure, Cost of Capital, and Gas Transmission Costs

by

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A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES

IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE

DEGREE OF MASTER OF ARTS

DEPARTMENT OF ECONOMICS

CALGARY, ALBERTA, CANADA

January, 1999

0-612-38540-X

ABSTRACT

The single most important cost in the Canadian gas transmission industry is the cost of financial capital. Under the current regulatory framework, the NEB has protected the monopoly position of Canadian gas transmission companies by discouraging by-pass and pipe on pipe competition. This has allowed Canadian gas pipelines to be highly levered and yet attract both debt and equity at relatively low rates. Recent actions by the NEB and events in the industry have suggested that the current regulatory framework is beginning to change. Specifically, the NEB appears to be encouraging by-pass and pipe on pipe competition within the Canadian gas transmission industry. The introduction of by-pass and pipe on pipe competition could shift existing risk from customers to shareholders, and increase the overall level of risk exposure in the industry. A substantial increase in risk exposure may negatively impact the capital structure, cost of capital, and gas transmission costs.

ACKNOWLEDGEMENTS

I am indebted to several people: first and foremost, my supervisor, Dr. Robert Mansell, for his guidance, support, and insight. Without his patience and encouragement this thesis would not have been possible. I would like to thank Dr. McKenzie and Dr. Sick for their comments which has helped me shape this thesis into its final form. I would also like to thank my parents, Luba and Merl, for their love and support, especially during my time spent at university. My greatest debt is to Denise Bracko, for her editorial assistance and criticisms, love and encouragement, and sense of humor which has made this possible.

For Denise, of course

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ABBREVIATIONS

the Accord	"Agreement on Natural Gas Pipeline Regulation, Competition and Change to Promote a Competitive Environment and Greater Customer Choice", dated 7 April 1998 and signed by the Canadian Association of Petroleum Producers, NOVA Corporation, NGTL, the Small Explorers and Producers Association of Canada, and TCPL.
AFUDC	Allowance For Funds Used During Construction
Alliance	Alliance Pipeline Ltd. Partnership
ANG	Alberta Natural Gas Company Ltd
Bcf/d	Billion Cubic Feet Per Day
Btu	British Thermal Units
CAPP	Canadian Association of Petroleum Producers
CBRS	Canadian Bond Rating Service
CWIP	Construction Work in Progress
FERC	Federal Energy Regulatory Commission
Foothills	Foothills Pipe Lines Ltd.
Mcf/d	Thousand Cubic Feet Per Day
NEB	National Energy Board
NGTL	NOVA Gas Transmission Limited
SEPAC	Small Explorers and Producers Association of Canada
TCPL	TransCanada PipeLines Limited
TQM	Trans Quebec & Maritimes Pipeline Inc.
Westcoast	Westcoast Energy Inc.

DEFINITIONS

Business Risk:	The basic risk involved in the firm's day to day operations. This includes a firm's regulated and non-regulated businesses.
Cost of Capital:	The expected rate of return prevailing in capital markets on alternative investments of equivalent risk.
Financial Risk:	Risk that affects the ability of a firm to raise additional financial capital.
Funded Debt:	Represents the average principal of debt capital associated with the utility investments projected to be outstanding during the test year.
Light-Handed Regulation:	This implies that regulation is on a complaints basis.
Market Risk:	Industry-wide sources of risk that may be caused by discounting, by-pass, loss of market share, alternate fuels, and competition.
Netback:	Is the delivery price less the transportation costs.
Regulatory Risk:	Risk to the industry resulting from changes in regulatory rules, policy, and environment.
Stranded Costs:	Costs become stranded when investments made in the prior regime of cost of service regulation cannot expect to earn their cost of capital as a result of the proposed transition to the new competitive rules, either because the investments themselves cannot earn a sufficient return or because the costs of prior commitments cannot be recovered.
Unfunded Debt:	Represents the portion of the capital structure that remains to be raised by long-term financing.

Chapter 1 - Introduction

1.1 BACKGROUND

The Canadian natural gas pipeline industry has generally been tightly regulated. This regulation has served to minimize risk for pipeline shareholders and promote a high debt-to-equity ratio in the capital structure. Generally, these factors have minimized the cost of capital component and the overall cost of gas transmission service. The cost of capital is a major cost component for Canadian natural gas pipelines. As shown in Table 1.1, the cost of capital (including capital recovery or depreciation) typically represents over half of the total costs. Therefore, it is of great importance that regulators carefully

TABLE 1.1: CANADIAN GAS PIPELINE REVENUE REQUIREMENTS - 1996 ($ MILLIONS & SHARE)

	Return		Depreciation		O & M[1]		Taxes		Total
ANG	$15.9	20.0%	$8.1	10.2%	$51.9	65.2%	$3.7	4.6%	$79.6
Foothills	$63.4	40.8%	$36.9	23.7%	$44.6	28.7%	$10.5	6.8%	$155.4
TQM	$31.7	47.4%	$13.8	20.6%	$8.1	12.1%	$13.3	19.9%	$66.9
TCPL	$721.6	40.0%	$234.0	13.0%	$609.7	33.8%	$237.9	13.2%	$1,803.2
Westcoast	$220.8	44.1%	$63.6	12.7%	$140.8	28.1%	$76.0	15.2%	$501.2

Source: National Energy Board (1997a: 39).

consider the effects of decisions on the risk exposure for pipeline shareholders and the industry. A significant increase in risk exposure could negatively impact the debt-to-equity ratio, cost of capital, and cost of gas transmission. If the increase in the cost of gas transmission is significant, this would also affect tolls and possibly, the profitability of pipeline companies.

Currently, there are indications of substantial change in the regulation of this sector and the allocation of risk. The allowance of by-pass pipelines, movement towards pipe on pipe competition, and the trend towards light-handed regulation[2] are examples of shifts that will likely expose pipeline shareholders to greater risks than previously. There

[1] O & M is operating and maintenance costs.
[2] See Definitions for an explanation of light-handed regulation.

are many fundamental implications such as: the likelihood and sustainability of effective competition to replace tight regulation; transition mechanisms and the allocation of stranded costs; the effects on capacity development, utilization and operating costs; the effects on the capital structure and the cost of capital; and the overall effects on tolls.

1.2 OBJECTIVES

The objective of the thesis is to examine how change in risk exposure for pipeline shareholders affects the capital structure, cost of capital, and cost of gas transmission for Canadian natural gas pipelines. Based upon the results, the thesis will discuss the implications for tolls and provide an outlook for the industry. Other objectives include explaining why there is a difference in capital structure between U.S. and Canadian natural gas pipelines; outlining the potential sources of risk that could affect the Canadian pipeline industry; determining whether the Canadian gas transmission industry is currently operating with an optimal capital structure; critiquing the current policies of the National Energy Board (NEB) in regard to the capital structure/cost of capital issue; and, examining how significant of a role the Canadian tax system plays in determining the capital structure for pipelines. The results from the thesis will also provide further insight to the capital structure/cost of capital issue in the literature.

1.3 RELEVANCE OF THE THESIS

The effects of change in risk exposure on capital structure, cost of capital, cost of gas transmission, and in turn, the implications for tolls, have not been well-researched. Finance literature has generally examined the impact of leverage on the cost of capital and regulatory institutions have conducted capital structure/cost of capital studies with the objective of streamlining regulatory costs. However, such studies have not been well focused. For example, in 1994 the NEB examined the capital structure/cost of capital issue for its oil and gas pipelines.[3] The result of this hearing was the NEB deriving a cost

[3] See National Energy Board, Multi-cost pipeline hearing, RH-2-94.

rate formula and deeming a common equity ratio that its pipelines would use in their ratemaking methodology.[4] This was seen as an improvement since many rate cases have spent lengthy hours continually disputing how cost rates and the common equity ratio should be determined. However, the use of such formulas should not suggest that Canadian gas transmission companies are minimizing their cost of capital or cost of gas transmission service.

Furthermore, events in the Canadian gas transmission sector suggest that it is uncertain whether the industry fully comprehends how risk exposure can affect the capital structure, cost of capital, and cost of gas transmission for Canadian gas pipelines. Recently, there has been an increase in demand for pipeline capacity from Alberta to Eastern Canada and the U.S. Midwest. Constrained pipeline capacity has created a surplus of gas supplies in Alberta and has pushed down the basin price. In turn, this has caused the price differential between Alberta-Eastern Canada and Alberta-U.S. Midwest to at times be greater than the full cost of transportation (that is, fixed costs plus variable costs). Therefore, there have been large economic gains (above the regulated cost of transportation) for buyers transporting gas from Alberta to Eastern Canada and the U.S. Midwest (Natural Gas Analyst, 1997b: 9). The large price differentials between markets have indicated that pipeline capacity out of Alberta can be increased.[5] Most studies examining this issue have analyzed the impact of increasing pipeline capacity on the Alberta basin price and continental pricing dynamics. However other issues, such as the impact on transmission costs, should also be considered.

In the Canadian natural gas pipeline industry, several categories of risk affect the overall level of risk exposure. These are market, business, regulatory, and financial risk.[6] To accommodate the increasing demand for pipeline capacity out of Alberta, it appears

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[4] For example, in 1995 the NEB determined that the rate of return on common equity would be 12.25% for Group 1 gas pipelines. Group 1 gas pipelines include: Alberta Natural Gas Company Ltd. (ANG), Foothills Pipe Lines Ltd. (Foothills),TransCanada PipeLines Limited (TCPL), Trans Quebec and Maritimes Pipeline Inc. (TQM), and Westcoast Energy Inc. (Westcoast). With regard to capital structure, the NEB deemed a 30% common equity ratio for ANG, Foothills, TCPL, and TQM and a 35% common equity ratio for Westcoast. This will be explained in more detail in Section 2.1.

[5] For example, the Canadian gas transmission industry has responded with several pipeline expansions to the U.S. Midwest. Specifically, Northern Border Pipeline Co., TCPL, and Alliance Pipeline Ltd. Partnership (Alliance) will provide an additional 2.4 bcf/d of capacity out of Alberta by the end of 2000.

that the NEB may allow or encourage pipe on pipe competition and by-pass within the Canadian gas transmission industry. Such a change in regulatory policy and operating environment would shift existing risk from transmission customers to pipeline shareholders.[7] Furthermore, market and regulatory risk for Canadian gas pipelines would intensify, thereby increasing the overall level of risk exposure in the industry. Given the large percentage of total costs represented by the cost of capital, an increase in risk exposure is expected to have a significant affect on the cost of gas transmission and the rates paid by customers. If there is a significant increase in the rates paid by customers, this could have a substantial impact on system utilization, producers' netbacks,[8] investment and expansion proposals, the role of the NEB, and the profitability of pipeline companies. Therefore, the research presented here seems timely.

1.4 SUMMARY OF THE MODEL

The potential risks that could impact the Canadian gas transmission industry are new. Therefore, it is uncertain how shareholders, bond rating agencies, and capital markets will react. Because of this, it would have been difficult to use an analytical optimizing framework to measure the effects of changes in risk exposure on capital structure, cost of capital, and gas transmission costs for Canadian gas pipelines. To address this problem, the thesis employs a non-optimizing spreadsheet/simulation model that incorporates bond rating guidelines. Various sensitivities and simulations are used to capture different reactions. Overall, the model demonstrates how a change in risk exposure affects the capital structure, cost of capital, and transmission costs for a Canadian gas pipeline that uses cost of service pricing methodology.

For each Canadian gas pipeline the vintage and transmission systems are different. The older the pipeline and the more depreciated it is, the smaller the cost of capital component relative to the other costs. Therefore, a change in risk exposure would

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[6] See Definitions for an explanation of market, business, regulatory, and financial risk.

[7] Transmission customers include distribution companies, large-retail customers, gas marketers, and resellers.

[8] See Definitions for an explanation of netbacks.

produce varying results for each Canadian gas transmission system. In this thesis, the model and simulations involve the system of TCPL.[9] Implications for tolls and the outlook for the industry will be based upon the results for this benchmark.

1.5 SUMMARY OF THE RESULTS AND CORE IMPLICATIONS

Based on the non-optimizing spreadsheet/simulation model, the results indicate that an increase in risk exposure may decrease the debt-to-equity ratio and increase the cost of capital for Canadian gas pipelines. The significance of these affects is dependent upon the magnitude of the increase in risk exposure and whether stranded costs are expected.[10] If Canadian gas pipelines do not face an increase in risk exposure, but are allowed to determine their own capital structure within a modest range of the common equity ratio deemed by the NEB, the results indicate that the cost of gas transmission could change by a maximum of 2%. However, if by-pass and pipe on pipe competition are introduced, the impact on the cost of gas transmission and tolls is heavily dependent upon stranded costs. If stranded costs are not expected, the simulations demonstrate that transmission costs and tolls may increase a maximum of 10% from their current state. On the other hand, if stranded costs are expected, the cost of gas transmission and tolls could increase a minimum of 10%.

The results suggest that the NEB may want to reconsider its current policy stance and take into account the implications on risk exposure, capital costs, and tolls in making decisions concerning by-pass and the introduction of pipe on pipe competition. By ignoring these implications there is a possibility that the end result will be higher, not lower tolls. The results also suggest that even in the absence of further moves to competition and light-handed regulation, regulators should relax the restrictions on capital structure. Instead of determining the optimal capital structure for its pipelines, the NEB should focus on the minimization of risk exposure faced by transmission companies

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[9] All references and data for TCPL is prior to its merger with NOVA Gas Transmission Limited (NGTL). The new company would still be exposed to the same risks as other Canadian gas transmission companies. Therefore, the recent merger of these companies is not expected to significantly affect the results and conclusions of the thesis.

[10] See Definitions for an explanation of stranded costs.

and its shareholders. This would allow companies to be highly levered and yet attract low cost rates to finance their capital requirements.

Nonetheless, if the NEB decides to allow by-pass and pipe on pipe competition into the industry, it will have to reevaluate some of its policies and consider the core implications for the Canadian gas transmission industry. These include:

- The NEB reevaluating its policies towards entry and investment, negotiated settlements, and stranded costs.
- Gas transmission companies evaluating how such an increase in transmission costs will impact their rate design. Specifically, how can tolls be adjusted without greatly impacting the utilization rate on their system and raising the possibility of a death spiral?
- The NEB evaluating whether any changes in rate design violates the objective of "fairness and equity" which, among other things, requires that tolls be "just and reasonable".
- Uncertainty over the ultimate regulatory rules and a significant increase in transmission costs may adversely affect the financial health and investment decisions of gas transmission companies and the industry as a whole. This could result in less taxes and royalties, and fewer employment opportunities as companies find other markets for their business.
- Shippers realizing that the move to competition in the Canadian pipeline industry will lead to greater costs and uncertain benefits. Often, it is suggested that competition would produce benefits such as: lowering risk and rates for shippers; increasing the quality and reliability of service; and, presenting more options for customers. The research presented here suggests that the introduction of by-pass and pipe on pipe competition could increase transmission costs at least 10% from what it otherwise might be. Such an increase could constitute rate shock, greatly affect producers' netbacks, and must imply that not all rates for customers will be lower. One may expect that in a more competitive environment where there is excess pipeline capacity, shippers would try to force tolls down to as low as variable costs. This is due to shippers acknowledging that pipelines only need to recover these variable costs

to stay operational in the short run. However, transmission companies will have to recover fixed and variable costs to stay operational in the long run. Therefore, from a long run perspective, one would expect that for at least some customers, rates will be higher from what they otherwise might be. Furthermore, under current cost of service pricing methodology in the Canadian gas transmission industry, there is no incentive for gas pipelines to reduce costs by decreasing quality of service. Therefore, it is uncertain whether a competitive environment would improve the quality of service currently provided. It is also uncertain whether reliability of service will be improved when customers could be contracting a greater percentage of their gas transmission service with short term firm and interruptible service contracts. Therefore, to argue that in a more competitive Canadian gas transmission industry, all customers will have better quality and reliability of service, and lower rates, does not appear to hold.

Overall, the results and implications suggest that prior to adoption of a policy of approving projects involving by-pass and pipe on pipe competition, it would be important to establish whether the benefits outweigh the higher costs. Any shift in the current regulatory or operating framework must be supported by a high probability that the alternative regulatory mode will produce net benefits.

1.6 OUTLINE OF THE THESIS

Chapter 2 outlines the necessary background information and literature. This includes the motivation of the thesis, a literature review, a discussion of the potential risks that could affect the industry, an explanation of cost of service pricing, and the implications of stranded costs for the pipeline industry. The contribution of the thesis is noted at the end of the chapter.

An outline of the analytical framework is presented in Chapter 3. After the methodology is discussed, an explanation and presentation of the non-optimizing spreadsheet/simulation model is outlined. The chapter concludes with a summary of the various sensitivities and simulations that will be tested. The calculations and definitions employed in the model are presented in Appendix B.

Chapter 4 provides a summary of the results and a discussion of the most likely scenarios in the short run and long run. The complete results from the simulation sets can be found in Appendix C.

A summary of the key results, a critique of current policies, and a discussion of other implications is presented in Chapter 5. This section also discusses some possible directions for future research.

Chapter 2 - Background Information and Literature Review

The objective in this chapter is to discuss relevant background information and literature. The motivation for the thesis is presented in Section 2.1 where the focus is on the differences in capital structure and regulation between U.S. and Canadian gas pipelines. The next section provides a brief review of the capital structure and cost of capital literature. After this, an explanation of the difference in capital structure between Canadian gas pipelines and their U.S. counterparts is provided. Section 2.4 outlines the potential risks that could affect the Canadian gas transmission industry. The next section provides an overview of cost of service pricing. The effects of change in the allocation of risk are discussed in Section 2.5. This section examines how a change in risk exposure for pipeline shareholders affects the capital structure, cost rates of capital, bond ratings, determinants of cost of service pricing, and the investment decisions of pipeline companies. Section 2.6 is a review of studies that have focused on the effects of leverage and regulatory environment on the cost of capital. Background information on stranded cost risk and its implications for pipelines is examined in Section 2.7. Section 2.8 outlines the contribution to the literature.

2.1 MOTIVATION FOR THE THESIS: DIFFERENCES IN CAPITAL STRUCTURE AND REGULATION BETWEEN U.S. AND CANADIAN GAS PIPELINES

The motivation for the thesis originated from several observations in the North American gas transmission industry. An examination of Tables A1 and A2 (Appendix A) indicates that the average debt ratio for Group 1 Canadian gas pipelines is 67%. On the other hand, the average debt ratio for Major Interstate U.S. gas pipelines is 34%. Tables A3 and A4 (Appendix A) indicate that the average bond rating for the debt issues of Canadian gas pipelines is A. On the other hand, the average bond rating for the debt issues of Major Interstate U.S. gas pipelines is B++.[11] Clearly, these are major differences, with Canadian gas pipelines generally having a higher debt ratio and bond rating.

There is also a significant difference in regulation between the U.S. and Canada. The Major Interstate U.S. gas pipelines are regulated by the Federal Energy Regulatory Commission (FERC). With regard to the regulation of its pipelines, the FERC has generally taken a policy stance of "light-handed" regulation. This implies that regulation is on a complaints basis. Therefore, the FERC generally does not hold yearly toll hearings, encourages negotiated settlements within the industry, and it does not attempt to dictate the capital structure for its pipelines. The FERC often only intervenes when pipeline companies and their customers are unable to reach a negotiated settlement on tolling matters.

With regard to the capital structure and cost of capital issue, the FERC believes that slight variations in a pipeline's capital structure from year to year will not significantly impact the cost of capital and the rates for shippers. Sherwin and McShane (1994: 32-33) explain that:

> U.S. regulation typically accepts the proposition that choice of capital structure is, within a considerable range, the prerogative of management, partly on the premise that management is in the best position to appraise the business risks of its operations and partly in the belief that changes in capital structure do not significantly impact on the overall cost of capital.

The FERC would deem a debt-to-equity ratio only if a subsidiary has a capital structure that is not in line with the parent company. An explanation for the FERC's policy stance is that the cost of capital (not including capital recovery or depreciation) has been estimated to be approximately 18% of the total costs for U.S. pipelines (Sherwin and McShane, 1992: 10). Therefore, a change in the capital structure is expected to have little impact on total revenue requirements, transmission costs, and tolls.

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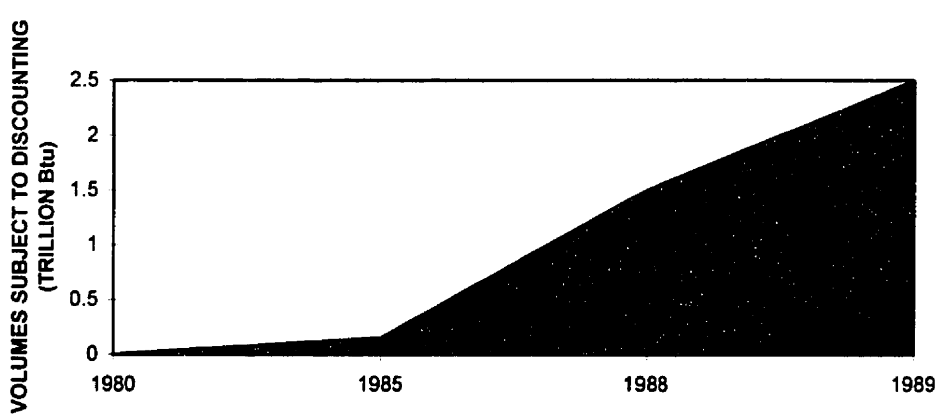
[11] The bond ratings are based on the Canadian Bond Rating Service (CBRS) standards. Note that the CBRS does not rate U.S. gas transmission companies. The rating for U.S. gas transmission companies was determined by Moody's which uses a different rating scale then CBRS. Moody's ratings were converted to the equivalent CBRS ratings. Table A5 (Appendix A) shows the bond rating comparisons between various agencies. Descriptions of the various bond ratings are presented in Table A6 (Appendix A).

The U.S. gas transmission industry is also characterized by pipe on pipe competition and by-passes. Since the early 1990s, the FERC has accepted by-pass and has emphasized its regulatory objective of encouraging competition in the gas transmission industry. For example, it has stated:

> The Commission supported the industry's efforts and continued to develop and exercise new ways to nurture competition through the use of market driven principles and a regulatory framework that allows and promotes competition where appropriate. The Commission's promotion of competition is balanced against the potential abuses that can occur in the pipelines transportation sector of the industry, where the potential for the exercise of market power still exists (FERC, 1996a: 17).

Under such conditions, transmission customers appear to have benefited from more service options and market based rates. However, pipe on pipe competition and by-pass have also resulted in several negative impacts for the U.S. gas transmission industry. For example, in a more competitive environment transmission companies have been discounting rates to attract customers. As shown in Figure 2.1, the volume of gas subject to rate discounting has increased from approximately 0.25 trillion Btu in 1985 to over 2.5 trillion Btu in 1989. The concern with rate discounting is that it implies less revenue for pipelines than if discounting were not necessary (Kolbe, Tye, and Myers, 1993: 194).

FIGURE 2.1: GROWTH IN DISCOUNTING IN THE U.S. NATURAL GAS PIPELINE INDUSTRY

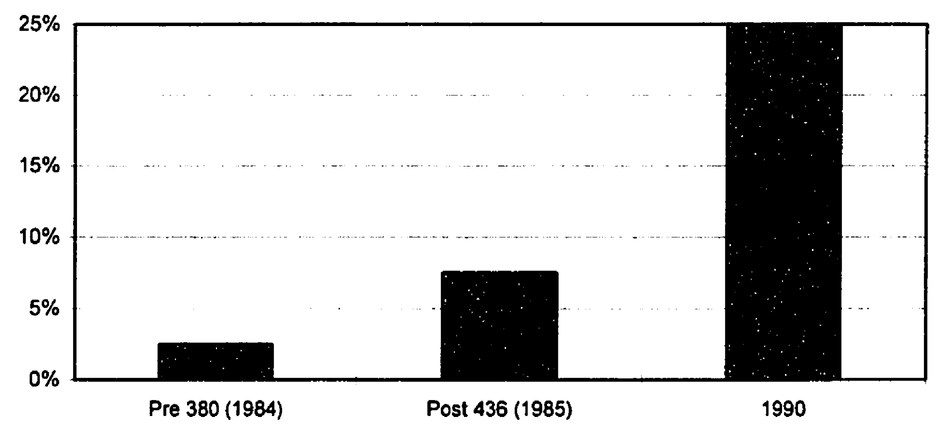


Source: Kolbe, Tye, and Myers (1993: 196)

Furthermore, pipe on pipe competition and by-pass has resulted in excess capacity and an uneconomic use of capital. For example, the average utilization rate for a U.S. gas pipeline (excluding the southwest region) is approximately 68% (Sherwin and McShane, 1992: 14). On the other hand, the average utilization rate for Canadian gas pipelines is over 90%. Therefore, there appears to have been unnecessary pipeline expansions in the U.S. gas transmission industry.

The low utilization rates in the U.S. has also resulted in customers switching their service contracts from firm transportation service to short term firm and interruptible service contracts. In response, gas transmission companies have allocated a greater percentage of fixed costs to interruptible service. Figure 2.2 illustrates that in the U.S. gas pipeline industry, the percentage of fixed costs allocated to interruptible transmission has increased approximately from 2.5% in 1984 to 25% in 1990. This is a concern as the

FIGURE 2.2: PERCENTAGE OF FIXED COSTS ALLOCATED TO INTERRUPTIBLE SERVICE IN THE U.S. GAS PIPELINE INDUSTRY



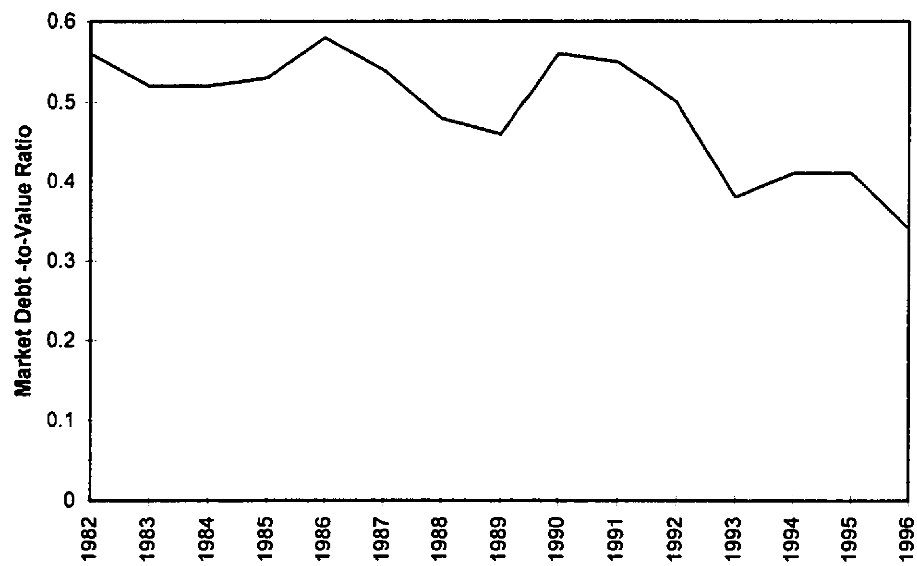
Source: Kolbe, Tye, and Myers (1993: 195).[12]

[12] Note that Order 380 (June 1984) eliminated minimum bill payments, but not take or pay obligations. Order 436 (October 1985) required open access to transportation.

combination of rate discounting and the increasing reliance on interruptible service for fixed cost recovery may imply that fixed costs are not being recovered (Kolbe, Tye, and Myers, 1993: 195).

Overall, it is uncertain whether competition has provided any net benefits for the U.S. gas transmission industry. Risks such as by-pass, pipe on pipe competition, and the light-handed regulation of the FERC appear to have resulted in greater risk exposure for U.S. gas pipelines. This is reflected in a steady decline in the market debt-to-value ratio. As shown in Figure 2.3, the market debt-to-value ratio for U.S. gas pipelines has decreased from 0.56 in 1982 to 0.34 in 1996. Data on the rate of return U.S. gas pipelines

FIGURE 2.3: U.S. NATURAL GAS PIPELINE MARKET DEBT-TO-VALUE RATIO



Source: Kolbe and Borucki (1996: Table C-30) and FERC (1996b).

use in their tolling methodology is sketchy. However, if one assumes that since competition, the equity risk premium has either remained constant or increased, then this would infer that as the debt-to-value ratio has decreased over time, the cost of capital has increased. Therefore, it appears that the policies and light-handed regulation of the FERC have not necessarily minimized the cost of capital and in turn, the transmission costs for gas pipelines.

In comparison to the FERC, the NEB has traditionally played a more active regulatory role with regard to its gas pipelines. Mansell and Church (1995: 62) explain that:

> In cases of regulation of the Group 1 gas pipelines by the NEB, the regulator plays a very active regulatory role. In addition to the requirement of detailed reporting by the firm, the regulator continuously monitors the firm's operating results, regularly conducts audits and holds frequent hearings to establish tolls and implement other constraints. Yearly toll hearings for Group 1 pipelines usually consist of the determination and approval the allowed rate of return and transportation revenue requirements from which it can base its tolls.

Rate hearings also include the NEB setting or "deeming" a pipeline's capital structure for ratemaking methodology purposes. This implies that the capital structure a pipeline company uses to finance its capital may not correspond with what it uses for its ratemaking methodology. An explanation for the NEB's policy stance is that since the cost of capital is such a large percentage of the total costs, a change in leverage could have a significant impact on the revenue requirement, cost of gas transmission, and tolls.

In comparison with the FERC's reporting requirements, the NEB's requirements appear more burdensome. The scrutiny of expansion plans is more careful in Canada than in the U.S.; the frequency and depth of scrutiny of the pipelines' revenue requirement is also greater than in the U.S. However, the efficiency of the Canadian regulatory process – in terms of timely rendition of adjudicating decisions – far exceeds that of the FERC, where the typical elapsed time between the application for a rate increase and the final decision is 30 months (Sherwin and McShane, 1992: 23).

The Canadian natural gas transmission industry has also been characterized by little pipe on pipe competition in main transportation corridors. Historically, the NEB has not encouraged such competition and by-pass. This has allowed pipeline companies to exploit significant scale and other economies in an attempt to provide gas transportation service at the lowest possible cost. Furthermore, with the possible exception of TQM, Canadian gas pipelines have been operating at utilization rates of approximately 90%.

Therefore, there does not appear to be an uneconomic use of capital or excessive investment in the industry (Sherwin and McShane, 1992: 14).

Overall, the NEB's use of tight regulation combined with monopoly or highly concentrated provision of gas transmission service has resulted in low risk exposure for the pipeline industry and its shareholders. This has meant the use of high debt-to-equity ratios and low costs of financial capital.

The issue of why the debt-to-equity ratio differs so significantly between U.S. and Canadian gas transmission companies has not been well-researched. The common belief within the industry is that pipelines operating under the U.S. regulatory system are exposed to greater risks than is the case for pipelines operating within the Canadian regulatory system (Mansell and Church, 1995: 11). In order to fully conceptualize the difference in capital structure between U.S. and Canadian pipelines and reasons for the difference, it is useful to now turn to the theory of optimal capital structure.

2.2 CAPITAL STRUCTURE/COST OF CAPITAL LITERATURE

Before the path breaking work by Modigliani and Miller (1958), the traditional view was that since the cost of financing debt is less than equity, the optimal capital structure of a firm will consist of a high debt-to-equity ratio. The problem with this theory was its inability to explain how the optimal capital structure was determined and why the debt-to-equity ratio varied among industries.

Modigliani and Miller (1958) disputed the traditional view and revolutionized the finance literature. They proved that if the capital structure decision has no effect on the cash flows generated by the firm, the decision also will have no effect—in the absence of transaction cost—on the total value of the firm's debt and equity (Grinblatt and Titman, 1998: 489). To prove their theorem, Modigliani and Miller conjectured two propositions. Proposition I is:

$$V_j = S_j + D_j \qquad \textbf{(EQ. 2.1)}$$

where V_j = the market value of all the firm's securities or the market value of the firm

S_j = the market value of common equity

D_j = the market value of debt

Proposition I states that the market value of any firm is independent of its capital structure and is given by the summation of equity and debt holdings. Levered companies cannot command a premium over unlevered companies because investors have the opportunity of putting the equivalent leverage into their portfolio directly by borrowing on personal account (Modigliani and Miller, 1958: 270). As long as investors can borrow or lend on their own account on the same terms as the firm, they can "undo" the effects of any changes in the firm's capital structure. Therefore, capital structure is irrelevant assuming perfect capital markets and providing that the choice of a particular capital instrument does not affect the firm's investment, borrowing, and operating policy. If the total value of the firm "pie" is fixed, the firm's owners (its common stockholders) do not care how this pie is sliced (Brealey and Myers, 1984: 359).

Proposition II is:

$$K_E = K_U + (K_U - K_{RF})(D/E) \qquad \textbf{(EQ. 2.2)}$$

where K_E = cost of common equity

K_U = cost of common equity to an unlevered firm with the equivalent risk as the levered firm

K_{RF} = cost of risk free debt

D = market value of the levered firm's debt

E = market value of the levered firm's common equity

Proposition II states that as the debt-to-equity ratio increases, the cost of equity increases. The cost of equity increases because shareholders face greater risk (that is, the risk per share increases) as more debt is added to the capital structure. Under this assumption, the cost of equity is linearly related to the market value debt-to-equity ratio. It is also important to note that Modigliani and Miller assumed that corporate debt was risk free and constant. With regard to taxation, Modigliani and Miller assume that all personal income is taxed at the same rate. Therefore, personal taxation effects have no impact on the firm's capital structure decision.[13] Overall, Modigliani and Miller proved that under very strict assumptions, the cost of capital is independent of capital structure. Therefore, the cost of capital remains constant from a 100% common equity ratio to a 100% debt ratio.

The major criticism of Modigliani and Miller (1958) is that they ignored the effects of income taxes and assumed that the cost of debt would remain constant over the entire debt-to-equity ratio range. By ignoring the effects of income taxes, they disregarded the fact that debt financing provides a tax shield to corporations since interest payments are tax deductible. Furthermore, assuming that the cost of debt is constant and does not change as the debt-to-equity ratio changes, disregards the costs of financial distress. Moreover, assuming that investors can borrow at the same rates as companies is a very unrealistic assumption.

Modigliani and Miller (1963) revised their original model by accounting for the affects of income taxes on the after-tax returns of firms with different leverage. In their revised model, it was concluded that the optimal capital structure for a firm was 100% debt financing. The basis for this conclusion was that debt financing has one important advantage under the corporate income tax system in the U.S. and Canada, the interest that the company pays is a tax-deductible expense.[14] The revised model states that the after-tax cost of capital to a firm is not constant over the entire capital structure, but declines as more leverage is introduced into its capital structure. The revision corrected Proposition I and II. Proposition I now read as:

Value of the Firm = Value If All-Equity Financed + PV Tax Shield[15] **(EQ.2.3)**

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[13] This is discussed further, later in this section.

[14] In Canada a dividend tax credit has been introduced to partially offset any gains from debt financing. This is discussed further, later in this section.

[15] $$\text{PV Tax Shield} = \frac{\text{Corporate Tax Rate} \times D \times r_{debt}(1-T_p)}{r_{debt}(1-T_p)}$$

where T_p = Personal tax rate

Therefore, if all personal income is taxed at the same rate, personal taxation effects have no impact on the optimal capital structure.

On the other hand, Proposition II now reads as:

$$K_E = K_U + (K_U - K_{RF})(1-T)(D/E) \qquad \textbf{(EQ. 2.4)}$$

where K_E = cost of common equity

K_U = cost of common equity to an unlevered firm with the equivalent risk as the levered firm.

K_{RF} = cost of risk free debt

T = tax rate of the levered firm

D = market value of the levered firm's debt

E = market value of the levered firm's common equity

The major criticism of Modigliani and Miller (1963) is that various industries within North America do not finance their capital structure with 100% debt. There are also no dramatic differences between corporate debt now and WW II, when corporate income taxes were negligible or nonexistent (Brealey and Myers, 1984: 381). Therefore, the conclusion that interest tax benefits allow firms to finance their capital with 100% debt was inconsistent with the evidence.

Stiglitz (1969) and Rubinstein (1973) adapted the Modigliani and Miller (1963) model by introducing risky corporate debt. Their revision had no effect on Proposition I, but Proposition II was changed to:

$$K_E = K_U + (K_U - K_D)(1-T)(D/E) \qquad \textbf{(EQ. 2.5)}$$

where K_E = cost of common equity

K_U = cost of common equity to an unlevered firm with the equivalent risk as the levered firm.

K_D = the cost of risky debt

T = tax rate of the levered firm

D = market value of the levered firm's debt

E = market value of the levered firm's common equity

The addition of risky debt resulted in the cost of debt being a function of financial leverage. Therefore, as leverage increased, the cost of debt increased. Furthermore, the cost of equity changed non-linearly with leverage.

The major criticism of Stiglitz (1969) and Rubinstein (1973) is that their models ignored the costs of financial distress. Furthermore, their model led to the conclusion that the optimal capital structure for a firm consisted of 100% debt financing. Therefore, their conclusion was also inconsistent with the evidence.

Miller (1977) revised the Modigliani and Miller (1963) model by accounting for personal taxation. Miller acknowledged that the valuable interest tax shields described in the original Modigliani and Miller theory could not explain why all firms were not financed with 100% debt. It was recognized that investors have different personal tax rates and this could impact the optimal capital structure for a firm. In Miller's model all firms face the same tax rate, but investors face a variety of tax rates and have a lower tax rate on equity income than on bond income. Therefore, highly taxed investors buy bonds and lightly taxed investors buy stocks. Miller described an equilibrium of aggregate supply and demand for corporate debt, in which personal income taxes paid by the marginal investor in corporate debt just offset the corporate tax saving. Therefore, the after-all-tax income retention factors are the same for debt as for equity for the marginal investor:

$$(1-T_{PD}) = (1-T_{PE})(1-T_C) \qquad \textbf{(EQ.2.6)}$$

where T_{PD} = marginal investor's personal tax rate on debt

T_{PE} = marginal investor's personal tax rate on equity

That is, the marginal investor is indifferent to receiving the tax effects of debt income or equity income (Sick, 1998: 3). Overall, Miller's model led to the conclusion that there is no such thing as an optimal debt-to-equity ratio for any single firm.

The major criticism of Miller's equilibrium explanation is that it holds only under the assumption that all firms face approximately the same marginal tax rate. This assumption can be immediately rejected. Furthermore, Miller's model still ignored the costs of financial distress.

Sick (1990) acknowledged that different firms pay tax at different effective rates. He presented a revised interest tax shield model based on the Miller (1977) debt and taxes equilibrium which allowed for a distinction between the marginal firm's tax rate T_M and the marginal tax rate T_C (that is, the firm for which the cost of capital is being calculated). Sick concluded that if the firm pays taxes at the same rate as the marginal firm, $T_C = T_M$, the net interest tax shield is zero. However, if the firm pays a higher tax rate than the marginal firm, then the net interest tax shield reduces the cost of capital. On the other hand, if the firm pays a lower tax rate than the marginal firm, then the net interest tax shield increases the cost of capital (Sick, 1988: 3).

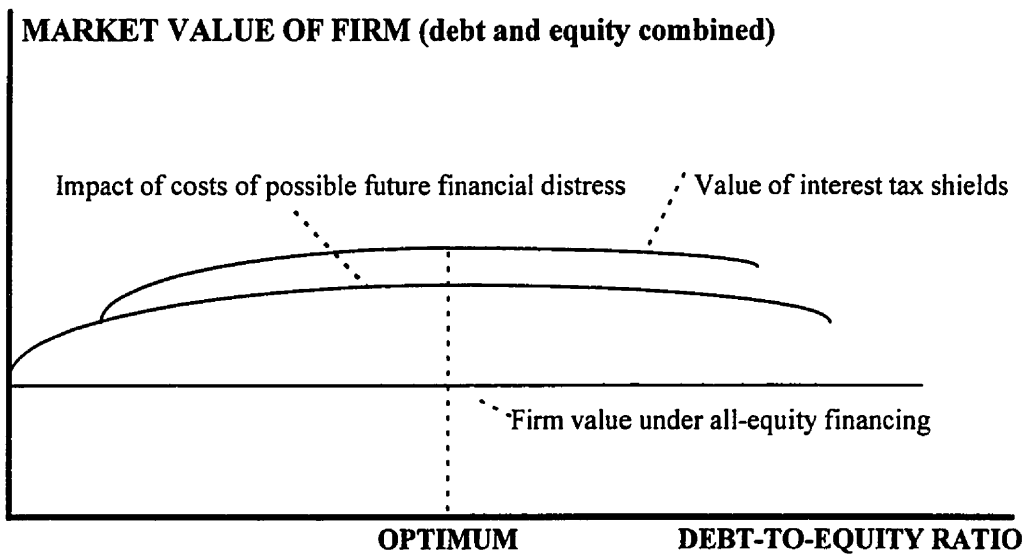
In finance, two theories have evolved to explain the capital structure behavior of firms. These are the "pecking order" and "static tradeoff" theories. In the pecking order theory, the firm prefers internal to external financing because firms are concerned about the reaction of investors to security issues. If internal financing is insufficient, firms prefer to issue debt rather than equity since the announcement of a stock issue will drive down the stock price. On the other hand, issuing debt seems to have little effect on stock prices since a debt issue is a less worrisome signal to investors (Giammarino, et al., 1996: 401). Giammarino, et al. (1996: 401) explain that these observations suggest a pecking order:

1. Firms prefer internal finance, since these funds are raised without sending any adverse signals that may lower the stock price.
2. If external finance is required, firms issue debt first and issue equity only as a last resort. This pecking order arises because an issue of debt is less likely to be interpreted by investors as a bad omen.

Therefore, in the pure pecking order theory the firm does not have an optimal capital structure.

The static tradeoff theory is the tradeoff of the tax advantages of borrowing against the costs of financial distress. Tax advantages of borrowing exist because the interest that a company pays on debt is a tax-deductible expense, while dividends and retained earnings are not. The interest tax shield is equal to the income tax rate multiplied by the interest payments. Financial distress accounts for bankruptcy and agency costs that may accrue to the firm as the debt-to-equity ratio increases. As a firm increases its debt usage, this increases the fixed claims against a firm's earnings stream, thereby increasing the probability that the firm will default on its debt holdings. Costs of financial distress include legal and administrative costs of bankruptcy, as well as the subtler agency, moral hazard, monitoring and contracting costs which can erode firm value even if formal default is avoided (Myers, 1984: 580). The following figure illustrates the theoretical optimum capital structure, as explained by the static tradeoff theory.

FIGURE 2.4: STATIC TRADEOFF THEORY

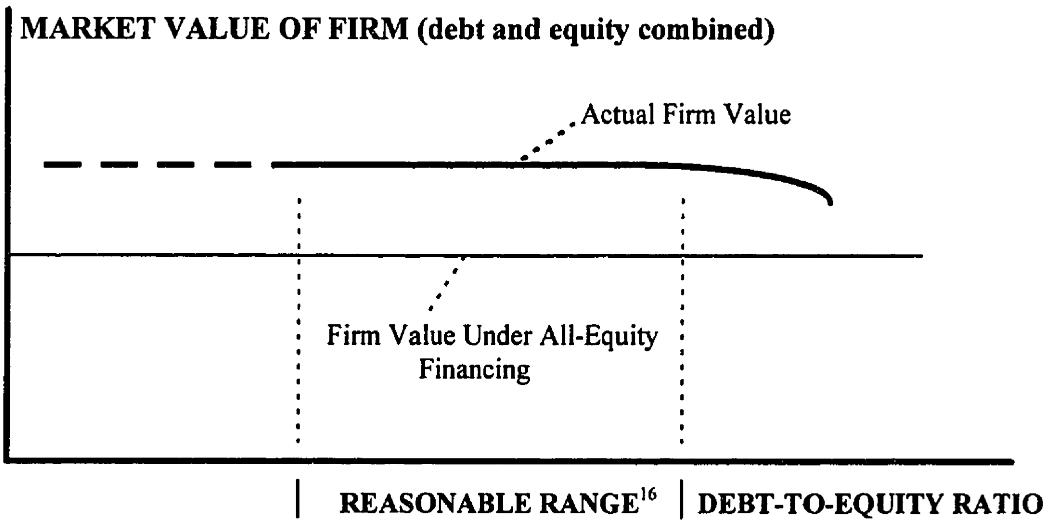


Source: Myers (1984: 577).

Figure 2.4 illustrates that the theoretical optimum capital structure is reached when the value of additional interest tax shields is offset by the impact of possible future costs of financial distress. At the equilibrium, the value of the firm is maximized and the overall cost of financial capital is minimized.

A criticism of the static tradeoff theory is that it ignores the taxation effects on investors. For example, the taxation of investors favors equity income because the maximum tax rate on capital gains is lower than the maximum tax rate on interest and dividends. Capital gains can also be deferred until shares are sold. Furthermore in Canada, investors receive a dividend tax credit which reflects part of the taxes already paid by the company on the dividend (Giammarino, et al., 1996: 38). Therefore, once the taxation effects on investors is considered, the tax benefits from debt financing may be irrelevant or even negative. This has been addressed in the literature by Myers (1984). The consensus is that the favorable treatment of equity income at the investor level partly offsets the interest tax shields realized at the corporate level. This suggests that the tax advantages of debt are less than they might first appear. However, there is still a tax advantage if firms finance their capital through debt. Therefore, acknowledging personal taxation effects may create a range in which changes in leverage have little effect on the cost of capital. The following figure illustrates the theoretical optimum capital structure, accounting for the taxation effects on investors.

FIGURE 2.5: STATIC TRADEOFF THEORY CONSIDERING INVESTOR TAXATION



Source: Myers (1992: 9).

Figure 2.5 illustrates that instead of a definitive optimal capital structure as illustrated in Figure 2.4, there is a range in which changes in leverage maximize the value of the firm and minimize the overall cost of financial capital. Therefore, changes in capital structure within this modest range should not have a significant effect on the cost of capital.

[16] "Reasonable" means more use of debt than many unregulated companies, but not so much that bond ratings slip or the utility faces any significant risk of financial trouble (Myers, 1992: 21).

2.3 STATIC TRADEOFF THEORY: AN EXPLANATION FOR THE DIFFERENCE IN CAPITAL STRUCTURE BETWEEN U.S. AND CANADIAN GAS PIPELINES

The optimal capital structure theory that perhaps best characterizes the financing behavior of gas transmission companies is the static tradeoff theory. Applying this theory to gas pipelines would suggest that the interest tax shield must be lower in the U.S. than in Canada. In the U.S., the composite tax rate (for revenue requirement purposes) is about 36-38% for gas transmission companies (Sherwin and McShane, 1992: 16). On the other hand, the composite tax rate for a Canadian gas pipeline is approximately 44%.

The determination of the costs of financial distress for U.S. and Canadian gas pipeline companies is much more difficult to measure. Estimates of the direct cost of bankruptcy range from an average of 2.5% for railroads (Warner, 1977) to 20% for smaller corporate entities and individuals (Baxter, 1967; Stanley and Girth, 1971; and Van Horne, 1976). Altman (1984) estimated both direct and indirect bankruptcy costs for 26 firms and he found these combined costs to average about 15% of total firm value.

With regard to the pipeline industry, there is no known study that has examined the costs of financial distress. Despite these shortcomings, one can conclude that U.S. gas transmission companies are generally exposed to greater risk than their Canadian counterparts. Risks such as by-pass pipelines, pipe on pipe competition, and the light-handed regulation of the FERC appear to have resulted in greater risk exposure for U.S. gas pipelines. This is supported from the fact that of the few cases of bankruptcy in the gas transmission industry, all have occurred in the U.S. For example, United Gas Pipeline and Columbia Gas Transmission both went bankrupt in 1991 and Transcontinental Gas Pipeline Corp. almost went bankrupt, but managed to escape by narrow margins (Kolbe and Borucki, 1996: 18). Overall, U.S. gas transmission companies have a lower interest tax shield and appear to face greater risk exposure than Canadian companies. Therefore, U.S. gas transmission companies would have a lower debt-to-equity ratio than their Canadian counterparts under the static tradeoff theory.

An examination of bond ratings appears to suggest that U.S. gas pipelines have a lower rating than their Canadian counterparts since bond rating agencies perceive U.S.

gas transmission companies to be exposed to a greater probability of financial distress. Table A6 (Appendix A) describes the various bond ratings that exist for several bond rating agencies. Bond rating agencies conclude that the greater the risk exposure faced by an industry, the riskier the debt holdings of a company, and the more susceptible that company is to changes in economic conditions. Therefore, the greater the risk exposure, the lower the bond rating. Another explanation is that when bond rating agencies determine the rating for a company's debt, the basis of the rating is on the entire operation of the company. Gas transmission companies operating in the U.S. are generally exposed to a greater percentage of non-regulated business than Canadian companies. Therefore, the exposure into other areas of business increases the overall risk of the company and results in a lower bond rating.

In summary, an examination of the capital structure and cost of capital between U.S. and Canadian gas transmission companies produces the following observations. U.S. gas pipelines have a lower interest tax shield and are exposed to a greater probability of financial distress. Therefore, the optimal capital structure exists at a lower debt-to-equity ratio. Furthermore, the cost of financial capital is much higher for U.S. gas transmission companies in comparison to Canadian companies. As shown in Table A7 (Appendix A), the ten-year government bond yield is generally higher in the U.S. than in Canada. Assuming that the spreads for the other capital instruments[17] are the same between U.S. and Canadian gas pipelines, the overall cost of capital should be much greater for U.S. gas transmission companies. This is supported from evidence in the industry. For example, the FERC has recently concluded that Northwest Pipeline Corp., Iroquois Gas Transmission System, and Alliance use a return on equity of 11.19%, 12.38%, and 14.00% respectively, in their ratemaking methodology.[18] On the other hand, the NEB recently determined the allowed return on equity for Canadian gas pipelines to

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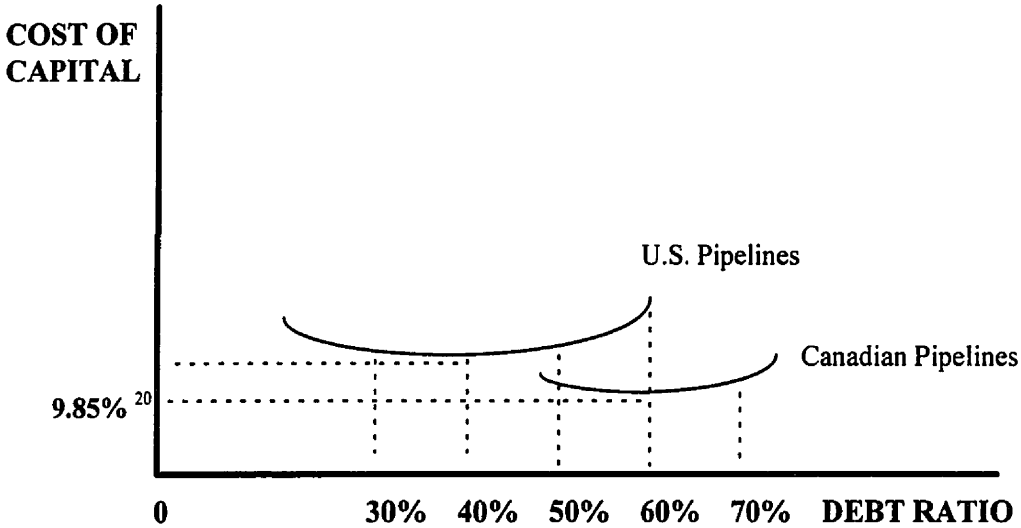
[17] Capital instruments include funded debt, unfunded debt, common equity, preferred share capital, and debentures.

[18] Northwest Pipeline Corp. 11.19% allowed return on equity. **Source:** Federal Energy Regulatory Commission (1998a).
Iroquois Gas Transmission System 12.38% allowed return on equity. **Source:** Federal Energy Regulatory Commission (1998b).
Alliance 14.00% allowed return on equity. **Source:** Federal Energy Regulatory Commission (1998c).

be 9.58%.[19] Based on these observations, the following figure illustrates the hypothesized capital structure and cost of capital curves that currently face U.S. and Canadian gas transmission companies.

FIGURE 2.6: COST OF CAPITAL FOR U.S. & CANADIAN GAS TRANSMISSION COMPANIES



U.S. Bond Ratings[21]	**A**	**B++**			
Canadian Bond Ratings		**A++**	**A+**	**A**	**B++**

Figure 2.6 illustrates the cost of capital for Canadian and U.S. gas transmission companies. In comparison to their U.S. counterparts, Canadian gas transmission companies have a lower cost of capital, higher bond rating, and higher debt-to-equity ratio. If Canadian gas transmission companies were faced with an increase in risk exposure, this could decrease their debt-to-equity ratio and bond rating for debt issues, thereby increasing the overall cost of capital. Therefore, one would expect that the cost of capital, bond rating, and debt-to-equity ratio for Canadian gas transmission companies

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[19] **Source:** National Energy Board (1998). It would be beneficial if one could undertake a more in-depth comparison of the rate of return between U.S. and Canadian pipelines. The problem is that data for U.S. pipelines is sketchy and limited, since the vast majority of rate of return and capital structure components of rate cases at the FERC are settled among the parties. Even the settlements do not necessarily specify the return on equity and capital structure, but rather the total dollars of return (equity and debt) and taxes.

[20] The cost of capital for TCPL in 1997 was 9.85%. **Source:** National Energy Board (1997:10).

[21] Refer to Tables A4 (Appendix A) and 3.1 for bond rating assumptions.

would move towards that currently used by their U.S. counterparts. The magnitude of the shift in the cost of capital curve is dependent upon the increase in risk exposure.

2.4 POTENTIAL RISKS THAT COULD IMPACT THE CANADIAN GAS TRANSMISSION INDUSTRY

This section outlines some policy changes and events that could impact the risk exposure of the Canadian natural gas pipeline industry.

Canadian gas pipelines are battling each other to expand to growing markets in the U.S. Some of the pipeline proposals such as Alliance,[22] are by-pass pipelines that may duplicate existing facilities. The NEB appears to be changing its stance and encouraging pipe on pipe competition and by-pass within the Canadian gas transmission industry. The potential problem is that allowing competition into the industry may jeopardize the economies of scale for existing companies and will not necessarily reduce the cost to transport gas.

In natural gas transmission a number of indivisibilities give rise to economies of scale and scope such as: volumetric returns to scale, construction costs, right-of-way, network management, and network configuration.[23] Empirically, Kruzel (1997) and Gordon, D., and C. Pawluk (1996) demonstrated that significant economies of scale exist in the Canadian natural gas pipeline industry. If economies of scale exist, it may be cheaper for an industry to allow a single firm to serve the entire market than any combination of two or more firms. Therefore, by-pass may duplicate existing facilities thereby producing stranded costs and increasing the cost to serve the market. Kolbe and Tye (1995: 27) explain that:

> Costs are stranded when investments made under cost-of-service regulation cannot expect to earn the cost of capital due to a transition to greater competition, because either: (1) the investments themselves cannot earn a sufficient return; or, (2) other costs or prior commitments cannot be recovered.

[22] Note that Alliance is owned by a consortium of existing pipeline companies.

[23] For a more detailed explanation of the economies of scale in the natural gas industry, refer to Mansell and Church (1995: 17-18).

Therefore, if by-pass, such as in the Alliance proposal, leads to stranded costs, there would likely be a significant negative impact on the overall natural gas transmission sector.

All parties do not view the introduction of competition in this manner. For example, two of the most significant intervenors to the recent Alliance proposal were TCPL and NGTL. During the Alliance hearing TCPL and NGTL announced that they were merging. After this, an "Agreement on Natural Gas Pipeline Regulation, Competition and Change to Promote a Competitive Environment and Greater Customer Choice" (the Accord) was signed by the Canadian Association of Petroleum Producers (CAPP), NOVA Corporation, NGTL, the Small Explorers and Producers Association of Canada (SEPAC) and TCPL. Parties to the Accord endorsed the following guiding principles:

1. Support competition and greater customer choice.
2. Need to construct competitive incremental pipeline capacity from the Western Canada Sedimentary Basin by both new competitors and existing pipelines in a timely, safe, and cost effective manner.
3. Need to effect regulatory changes that will provide existing and new pipelines equal opportunity to compete.

The signing of the Accord resulted in CAPP and SEPAC agreeing that they would not oppose the NGTL/TCPL merger if these parties agreed to drop their opposition to the Alliance Pipeline proposal. Once this agreement was met, the following comments were stated, demonstrating the attitude of the industry. "It's great that they've finally embraced competition" stated David Manning, president of CAPP in reference to TCPL and NGTL, and their acceptance of Alliance. "By getting together, we've sorted out a lot of thorny issues that were before the regulator and in fact we think we've been of assistance to the regulator in seeing a way forward in this industry," noted George Watson chief executive of TCPL. "The old pipeline paradigm of cost-of-service is behind us," Gwen Morgan, chief executive of Alberta Energy Co. Ltd. stated. "We can move from an era of pipelines to an era of producers" (Sharpe, 1998: C1, C2).

There is a perception by some, that competition is the ideal model for the Canadian gas transmission industry. However, this push for competition has taken place without a full examination of the impacts or net benefits. It is uncertain that competition will provide a more efficient environment when significant scale and other economies exist. Another problem is that the "pipe on pipe competition" that has existed in the U.S. gas transmission industry and appears to be emerging in Canada, is not truly competition. Competition is defined as an industry or market that is structured around a number of firms who individually do not display any form of market power or influence. These firms are price takers, produce a homogenous good or service that can be substituted between firms, and they supply their good or service to the same market as their competitors.

In the U.S. gas transmission industry and in the more competitive Canadian gas transmission industry that appears to be emerging, the number of pipelines is increasing. However, there is still a limited number of transmission companies operating in these markets. Therefore, transmission companies still have and will continue to have significant market power. Furthermore, new pipeline proposals, such as Alliance, must sign their shippers to fifteen year contracts. On the other hand, existing transmission companies generally sign their customers to contracts for five years or less.[24] Therefore, so-called "competing" pipelines are unable to offer customers similar service contracts. Moreover, in a more competitive Canadian gas transmission industry, so-called "competing" pipelines will not necessarily be regulated by the same agency. For example, NGTL is regulated by the Alberta Energy and Utilities Board, while Group 1 gas pipelines are regulated by the NEB. Since each regulatory agency differs in the manner in which it regulates pipelines, the rules of the game and the manner in which each transmission company can operate, may differ. There is also a significant difference in the markets that so-called "competing" pipelines are intended to serve. For example, the Alliance pipeline proposal is supposed to provide competition for NGTL in Alberta. However, NGTL was designed to deliver gas within Alberta and to the various export

[24] New pipeline proposals, such as Alliance, must demonstrate that their investment meets the needs of public convenience and necessity. Therefore, they must sign their shippers to fifteen year contracts.

points for delivery to other markets. On the other hand, Alliance will be transporting gas directly from Northwestern B.C. to Chicago. Therefore, these pipelines will be competing for supplies, but will be providing transportation services for different markets. Overall, one has to question whether new entry, such as in Alliance, is really competition or cherry picking? It appears that entry may be based more on inefficient regulation (for example, cross subsides to serve equity or other non-efficiency objectives) rather than market fundamentals (Mansell, 1998: 7). Therefore, it appears to be unreasonable to state that there is competition between pipelines when:

- transmission companies still display market power,
- are unable to offer customers similar service contracts,
- are regulated by different regulatory agencies, and
- there is a difference in the markets that so-called "competing" pipelines serve.

Under such conditions, it would be more acceptable to state that there is "imperfect competition".

One must also recognize that the allowance or encouragement of by-pass and pipe on pipe competition will allocate risk from transmission customers to shareholders. In a regulated monopoly environment with high utilization rates, pipeline customers are forced to contract their service with long-term or firm service agreements and hence, bear the risk of recovering the cost of transportation. However, in a more competitive environment with excess pipeline capacity, pipeline customers will switch their contracts from firm service to interruptible service. This in turn, will shift the risk of recovering costs from transmission customers to pipeline shareholders. Therefore, in a more competitive market, pipeline shareholders will bear the risk of recovering the cost of transportation.

Overall, such a change in regulatory policy and operating environment would shift existing risk from transmission customers to pipeline shareholders. Furthermore, uncertainty over the ultimate regulatory rules and a decrease in the market power of transmission companies will increase regulatory and market risk respectively. Therefore, the overall level of risk exposure for the Canadian gas transmission industry can be expected to increase. An increase in risk exposure would in turn, negatively affect the capital structure, cost of capital, and the cost of gas transmission for Canadian gas pipelines.

Another source of risk has arisen from the integration of the Canadian and U.S. gas markets. A large percentage of the volumes carried by Canadian gas pipelines are exported to the U.S. For example, 90% of the gas shipped on Foothills is delivered to the U.S. Midwest, U.S. Pacific Northwest, and California gas markets. Over 50% of the throughput on Westcoast is shipped to the export market, and ANG ships 80% of its throughput to California and 15% to the U.S. Pacific Northwest (NEB, 1995: 8-13). Overall, the export market has experienced tremendous growth in recent years. However, the export market is also inherently riskier than the domestic market because of greater pipe on pipe and interfuel competition. Canadian gas must compete with U.S. gas which is shipped to markets from a shorter distance. Furthermore, U.S. pipeline companies may be able to offer customers more competitive rates through rate discounting and the use of market based pricing.

The integration of North American pipeline markets has also increased the exposure of Canadian gas pipelines to policies and actions of U.S. gas transmission companies and regulators. TCPL has argued 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 cross-over ban on the systems of Pacific Gas Transmission and Pacific Gas & Electric, and coal seam subsidies. The implementation of FERC Order 636 has meant that, instead of contracting with creditworthy downstream U.S. pipelines, Canadian pipeline companies are dealing with replacement shippers who might not be as creditworthy. Foothills has argued 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. and Pacific Interstate Transmission Company as an example of such risks. This contract is being restructured as a result of the intervention of the California Public Utility Commission and this could result in a significant reduction in the Pan-Alberta Gas Ltd. to Pacific Interstate Transmission Company sales contract volumes. This in turn, may reduce demand for capacity on Foothills. Therefore, Canadian pipeline companies argue that U.S. federal and state governments, and regulators make decisions which are in the best interests of the U.S. natural gas industry and not necessarily those in Canada (NEB, 1995: 9,12).

In summary, the NEB appears to be on a path of allowing or encouraging pipe on pipe competition and by-pass in the Canadian gas transmission industry without conducting a thorough examination of the benefits and costs. Significant scale and other economies exist in the Canadian natural gas pipeline industry. Allowing by-pass could involve facilities duplication, leading to stranded costs, and increasing the cost of gas transmission. Furthermore, the NEB no longer appears to be setting the standards for the industry. Instead it is allowing transmission companies and producers to settle and negotiate issues. Therefore, there is potential uncertainty over the regulatory rules that will be applied to the natural gas pipeline industry, which itself, is a source of risk. Canadian pipeline companies also face greater pipe on pipe and interfuel competition associated with greater market integration. Overall, the market and regulatory risk facing Canadian gas pipelines and shareholders appears to be beginning to intensify, which will in turn, increase the overall level of risk exposure in the industry. Canadian pipelines will likely react by decreasing the debt-to-equity ratio, and will face higher costs for financial capital. This could have a significant impact on tolls.

2.5 OVERVIEW OF DETERMINANTS OF TOLLS UNDER COST OF SERVICE PRICING METHODOLOGY

Tolls in the Canadian natural gas pipeline industry have generally been set using cost of service pricing methodology. Traditional cost of service involves the setting of prices or tolls so as to cover all prudently incurred costs in providing the product of service, including a 'fair' return on investment (Mansell and Church, 1995: 57). The main determinants of traditional cost of service pricing are: cost of capital; return on rate base; depreciation expense; operations, maintenance and administrative expenses; taxes payable; and, other attributable costs. The allowed rate base is determined using historical data on investments, new additions, accumulated depreciation, capital in aid of construction (or surcharges), working capital, and various deferrals. Cost of capital requires a determination of the cost of funded debt, the cost of unfunded debt, and the appropriate return on equity. The approved cost of capital is a summation of the weighted average of debt and equity costs. For example,

$$r = (d \times r_d) + (e \times r_e) \qquad \textbf{(EQ. 2.7)}$$

where r = overall cost of capital

d = book value of the debt ratio

e = book value of the equity ratio

r_d = cost rate of debt

r_e = cost rate of equity

In traditional cost of service pricing, the approved cost of capital is equal to the allowed rate of return. The allowed return on rate base is equal to the approved rate base multiplied by the approved rate of return. Depreciation expense requires a decision to be made on the appropriate rate of depreciation to be applied to the various types of capital. Allowed operations, maintenance and administrative expenses require the regulator to review such things as the number of employees, the level of wages and benefits, the amount and the cost of office space, the amount and cost of maintenance work and so on. Taxes payable involves the estimation of municipal, capital, income and other taxes which will be levied on the firm and a decision on how any tax deferrals are to be treated in the calculation of current costs and revenue requirements. Other attributable costs are associated with a variety of items that include the costs for services purchased from other connected pipelines, regulatory costs, interim toll adjustments and often deferrals (Mansell and Church, 1995: 59-60). A simple cost of service regulation case involves setting the revenue requirements equal to the sum of the approved costs. In general,

$$RR = OM + D + MOT + YT + RORB + OAC \qquad \textbf{(EQ. 2.8)}$$

where RR = revenue requirement

OM = operating and maintenance

D = depreciation

MOT = municipal and other taxes

T = income taxes

RORB = return on rate base

OAC = other attributable costs

The average toll is calculated by dividing the revenue requirements by the utilization of the system. For example,

$$\text{Average Toll} = RR \div (LF \times \text{Capacity}) \qquad \textbf{(EQ. 2.9)}$$

where LF = load factor

In most cases the process used by the NEB begins with an application by a pipeline involving the submission of costs for a forward or test year.[25] These are then subjected to a hearing and a decision on the authorized costs on which the pipeline can base its tolls. The use of a forward or test year for costs produces some regulatory lag. Therefore, there is an incentive for the pipeline to minimize costs over the lag period. A frequent complaint is that cost of service pricing as used in the Canadian gas transmission industry, is inefficient because of potential A-J effects.[26] However, inefficiencies associated with the A-J effect can be minimized by assuring that the allowed rate of return does not significantly exceed the cost of capital. Furthermore, the NEB has the authority to disallow costs. This provides some disincentive for gas transmission companies to engage in wasteful practices with respect to both operating and capital expenditures. Another important characteristic of cost of service pricing is that it does not provide an incentive for companies to reduce costs by decreasing quality or reliability of service. Overall, if the regulator correctly sets the allowed rate of return, uses a forward or test year, allows some regulatory lag between hearings, and audits costs, cost of service pricing methodology will produce an efficient outcome.

To determine the rate of return on common equity, the NEB in RH-2-94, used the comparable earnings, discounted cash flow, and equity risk premium techniques. Based on the evidence presented, the NEB concluded that it would give primary weight to the equity risk premium technique. For example, in 1995 the NEB concluded that the yield on long-term Government of Canada bonds was 9.25% and a reasonable all-inclusive equity risk premium for the benchmark pipeline was 300 basis points. Therefore, the

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[25] Note that some pipelines such as Foothills, are regulated on an ex post versus test year basis.

[26] This effect is often described as the alleged tendency for regulated firms under rate of return regulation to inflate the size of the rate base if the fair rate of return set by the regulator exceeds the firm's cost of capital (Mansell and Church, 1995: 58).

allowed rate of return on common equity Canadian gas pipelines could use in their ratemaking methodology was 12.25%.

The NEB also implemented an adjustment mechanism that would make yearly adjustments to the approved rate of return on common equity. The rate of return on common equity is based on forecasted changes in long-term Government of Canada bond yields. Each November, the NEB determines 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 are averaged. To this figure is added the average spread between 10-year and 30-year Government of Canada bond yields. The adjustment mechanism for the rate of return on common equity is based on the following calculation. Each November, the NEB subtracts 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 is 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 (NEB, 1995: 30-31). The cost rate for other capital instruments (that is, debt, debentures, and so forth) are based on the market rate of return.

2.6 EFFECTS OF CHANGE IN THE ALLOCATION OF RISK

Pipe on pipe competition and by-pass will shift risk from some transmission customers to pipeline shareholders and increase the overall level of risk exposure in the gas transmission industry. The effects of a change in the allocation of risk from transmission customers to pipeline shareholders is examined in this section.

The impact on the cost of capital when competition enters a monopoly industry has been studied by Thomadakis (1976: 150-162), Sullivan (1978: 209-217), Subrahmanyam and Thomadakis (1980: 437-451), Booth (1981: 467-482), and Kolbe and Borucki (1998: 255-275). The conclusion from these studies is that the transition from monopoly to competition will increase the cost of capital of firms operating in that industry. There are several reasons for this. The most convincing reason is that the equity risk premium increases for a firm in the transition from a monopoly to competition. The Capital Asset Pricing Model states that the expected return on a given security equals the risk free rate plus a premium determined by the degree to which the return on security is likely to fluctuate with the return on the general market (Sullivan, 1978: 211). The smaller the market power of a firm, the greater the risk exposure relative to the general market, the higher the equity risk premium. Therefore, an increase in equity risk premium will increase the cost of financing capital and the overall cost of capital.

Kolbe and Borucki (1996) have examined the equity risk premium for the telecommunications industry in its transition from a monopoly to competition. They concluded that the equity risk premium has increased significantly since deregulation. For example, the average risk premium for AT&T prior to competition was 2.1%. Since competition has been implemented, AT&T's average risk premium has increased to 6.8% (Kolbe and Borucki, 1996: A-6).

The size differences among firms may also affect costs of financing capital. The size of the firm affects its transaction costs. A monopolist has easier access to capital markets than a competitive firm. Therefore, the monopolist will tend to face lower transaction costs and can attain a lower cost of capital (Booth, 1981: 467).

The affect of risk exposure on capital structure can be explained by the static tradeoff theory. The static tradeoff theory is the tradeoff of the tax advantages of borrowing against the cost of financial distress. If the risk exposure for Canadian gas transmission companies increased, this would increase the probability and costs of financial distress. Therefore, the tradeoff of the tax advantages of borrowing against the costs of financial distress would be in equilibrium at a lower debt-to-equity ratio.

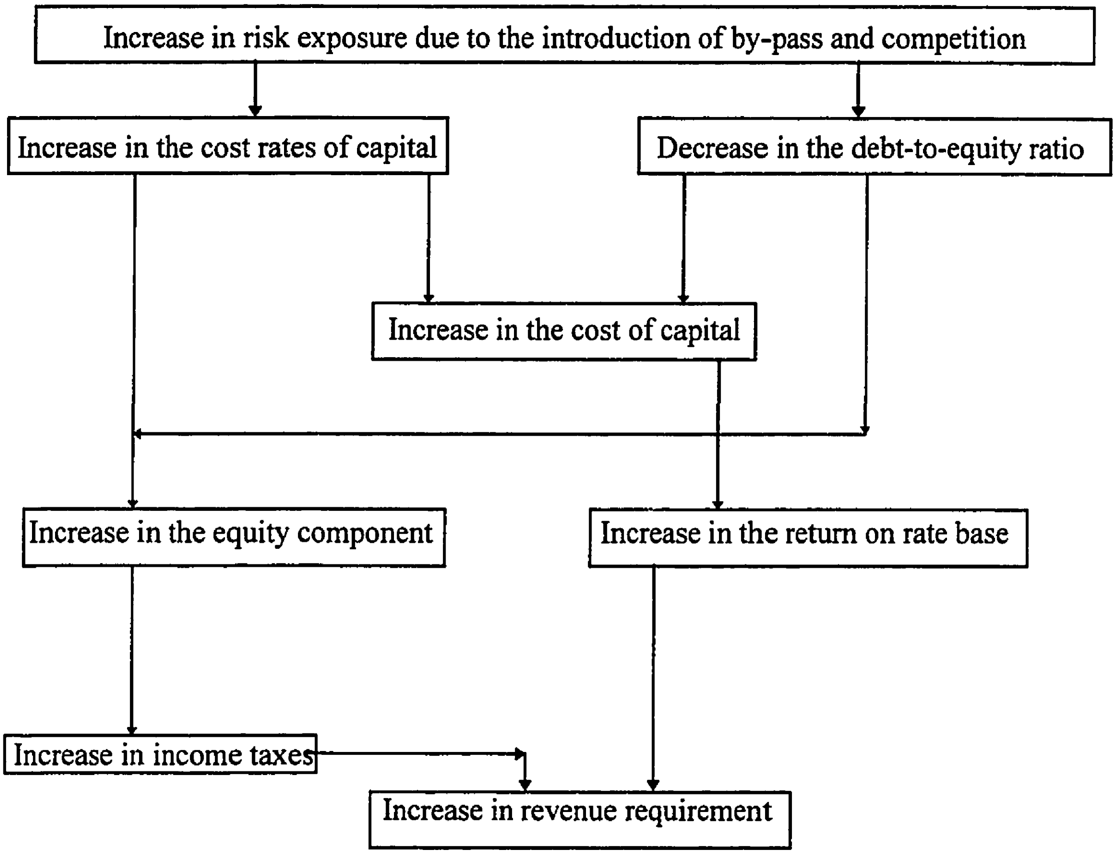
This conclusion is also supported by empirical evidence. Kolbe and Borucki (1996) examined the debt ratios for telecommunication firms in the transition from a monopoly to competition. It was concluded that the average debt-to-value ratio decreased to a level slightly greater than half of the ratio under monopoly (Kolbe and Borucki, 1996: A-2).

The impact of risk exposure on bond ratings depends on the reaction of gas transmission companies to changes in risk. For example, if the reaction to an increase in risk exposure involves a lowering of its debt-to-equity ratio, the bond rating could be unchanged. Therefore, the bond rating is dependent upon the capital structure that minimizes the cost of gas transmission.

It is also necessary to explain how a change in risk exposure affects the determinants of tolls under cost of service pricing methodology. Recall that simple cost of service regulation involves setting the revenue requirements equal to the sum of costs, including capital costs, operating and maintenance expenses, depreciation, and taxes (refer to EQ. 2.6). The introduction of by-pass and pipe on pipe competition is expected to increase the cost of capital and decrease the debt-to-equity ratio. An increase in the cost of capital (which is equal to the rate of return in traditional cost of service regulation) would increase the return on the rate base. A decrease in the debt-to-equity ratio and an increase in the cost of capital would increase the equity component and income taxes. The equity component is equal to the allowed rate base multiplied by the sum of the allowed weighted average costs of preferred and common equity. Therefore, the smaller the debt-to-equity ratio and the larger the cost rates of preferred and common equity, the greater the equity component and income taxes.

With regard to the other determinants, a change in the capital structure and cost of capital should have no affect on the operating and maintenance costs, depreciation, other attributable costs, and municipal and other taxes. Therefore, a change in the capital structure and cost of capital should only affect the income tax and return on the rate base determinants of cost of service pricing. Diagram 2.1 illustrates the impact of a change in risk exposure on the determinants of cost of service pricing.

DIAGRAM 2.1 EFFECTS OF A CHANGE IN THE ALLOCATION OF RISK ON COST OF SERVICE PRICING



Another area that could be affected by a change in risk exposure is the investment decisions of Canadian gas pipelines. Investment decisions are commonly based on a hurdle rate or the minimum required rate of return. If the expected rate of return on a project is below the hurdle rate, the project will not be accepted (Birk, 1989: 395). The company cost of capital is the opportunity cost of capital for the firm's existing assets and is used to value new assets that have the same risk as the old ones (Giammarino, et al., 1996: 264). Therefore, if the cost of capital increases due to an increase in risk exposure, the hurdle rate for new investments will also increase. Since the hurdle rate for new investments has increased, it may be the case that the probability of accepting new investments will have declined. Therefore, one could expect fewer investments to be undertaken. If fewer investments are undertaken, this could have a significant affect on the entire Canadian natural gas industry.

The reduction in future investments could also affect the income taxes of companies that use flow-through taxation. The natural gas pipeline industry generally uses straight-line depreciation to determine its tolls, and accelerated depreciation for its income taxes. Regulatory commissions have to decide whether taxes should be incorporated in price using "flow-through" or "normalized" methodology. In the former the benefits of accelerated depreciation are passed on entirely to customers in the years of tax savings. Under "normalized" treatment the income taxes recorded in the price are higher than actual taxes in the early years and lower in the latter years. This amounts to an interest free loan which is retained by the company. Kahn (1988: 33) explains that:

> Advocates of including in the cost of service only the taxes actually paid, which involves "flowing through" the benefits of accelerated depreciation to the customers, argue that the benefits are likely to be permanent-that is, that the amount of taxes saved is not really postponed but is, in effect, forgiven. And they are more right than wrong, provided the company's total investments grow over time at a sufficiently rapid rate. In that event, the tax postponements on its newer (and even larger investments will always exceed the higher taxes continually coming due on the older (and smaller) investments. Indeed, as long as total company assets grow at all, taxes will always be lower under accelerated amortization than they would otherwise be.

In the case of Canadian gas transmission industry, the NEB requires that all of its Group 1 gas pipelines (except Foothills) use flow-through taxation methodology.[27] Consequently, any increase in income taxes as a result of greater risk exposure for the pipeline company would lead to an immediate increase in tolls under cost-based pricing. Therefore, the affect of an increase in risk exposure on transmission costs and tolls would be intensified by the use of flow-through taxation methodology.

In summary, change in the risk exposure will impact the debt-to-equity ratio, cost of capital, bond rating, and investment decisions for Canadian gas pipelines. The significance of these impacts depends on the magnitude of the change in risk exposure and the reactions of shareholders, bond rating agencies, and capital markets.

2.7 CAPITAL STRUCTURE/COST OF CAPITAL STUDIES EXAMINING UTILITIES AND REGULATORY ENVIRONMENT

The most recent study on the capital structure/cost of capital issue in a U.S. utility context was undertaken by Brigham, Gapenski, and Aberwald (1987). They developed a computer model that examined the impact of changes in leverage on the revenue requirement for electric companies over a fifteen year time period. Brigham, Gapenski, and Aberwald concluded that changes in capital structure have little impact on a utility's revenue requirements or customer rates. Specifically, a five percentage point decrease in the debt ratio increased the revenue requirement by $18 million or by only 16/100th of one percent, fifteen years after the decision to change the capital structure. This in turn, results in the average customer's bill differing by only 29 cents or by only 16/100th of one percent (Brigham, Gapenski, and Aberwald, 1987: 19). Therefore, capital structure does affect the cost rates of debt and equity, but changes in these variables are offset by changes in the weights of each capital structure component which in turn, minimizes the impact on the revenue requirement.

A criticism of Brigham, Gapenski, and Aberwald (1987) is that they do not provide any information on the cost of capital relative to the total costs in the electric industry. It may be that changes in the capital structure have little impact on customer rates since the cost of capital is a small percentage of total costs in the electric industry. However, in the Canadian gas transmission industry, the cost of capital represents a large percentage of the total costs. Consequently, it is possible that change in the capital structure does not significantly affect the costs to electricity ratepayers, but this is not necessarily true for all other industries.

Gapenski (1987) conducted an empirical study which examined the relationship between equity costs and financial leverage for electric utilities. The primary objective of the study was to estimate empirically, the relationship between financial leverage and the costs of common equity and debt. The empirical portion of the study consisted of two models, an econometric and a bond rating guidelines model. The econometric model was

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[27] In the U.S., all gas pipelines use "normalized" taxation methodology (Sherwin and McShane, 1992: 16).

based on multiple regression techniques used to estimate the relationship between leverage and capital (debt and common equity) costs. The relationships were as follows:

$$k_s \text{ or } k_d = b_0 + b_1(\text{Leverage}) + b_2F_2 + \ldots + b_nF_n + e \quad \textbf{(EQ. 2.10)}$$

where k_d = cost of debt

k_s = cost of equity

The above equation states that either the cost of common equity or the cost of debt is the dependent variable, and financial leverage is one of the independent variables. Additional independent variables (the F_i 's) are included in the regression to account for other factors which might affect k_s or k_d (Gapenski, 1987: 7). These included its: (1) regulatory climate; (2) electric/gas sales mix; (3) fuel mix; (4) construction program in relation to operating assets; (5) nuclear construction program; (6) reserve margin situation; and (7) dividend policy.

The bond rating guidelines model was developed to estimate the relationship between the costs of capital (that is, both debt and equity) and financial leverage. Gapenski examined the electric industry using a sample of 66 U.S. companies. The bond ratings for the companies were as follows:

	Number of Companies	
Rating	**1983**	**1984**
AA+	0	5
AA	16	16
AA-	8	4
A+	9	13
A	10	5
A-	5	4
BBB+	7	8
BBB	6	5
BBB-	8	5
BB+	0	1
BB	1	0
	70	66

The model used Standard & Poor's published guidelines, along with yields on bonds and different ratings, to estimate the leverage/debt cost relationship (Gapenski, 1987: 7). For example, Standard & Poor's Rating Guidelines for electric utilities were:

Leverage Guidelines

Rating	1982	1985	Average Midpoint
AAA	Debt Under 45%	Debt Under 41%	Under 43%
AA	42 - 47	39 - 46	43.5
A	45 - 55	44 - 52	49.0
BBB	Over 53	50 - 58	54.0
BB	--	Over 56	Over 56.0

Gapenski then used Standard & Poor's Utility Index Yields to calculate the spread for bonds between the various bond ratings.

Standard & Poor's Public Utility Index Yields: Yield to Maturity

Rating	1983	1984	Average
AAA	12.62%	--	--
AA	12.64%	12.11%	12.38%
A	12.90%	12.42%	12.67%
BBB	13.61%	12.93%	13.27%

Therefore in 1983, the spread between AA and A issues was 0.26 percentage points, and between A and BBB issues, it was 0.71 percentage points. Gapenski constructed the following table which combined the bond rating guidelines and yield spreads to estimate the relationship between financial leverage and debt cost.

Impact of Leverage on Debt Cost

Book Value Debt Ratio	Book Value Debt-to-Equity Ratio	Change in Financial Risk Premium from Base Level Debt Ratio of 40%
40%	0.67%	--
50	1.00	+0.56
60	1.50	+1.76

Therefore, the bond rating guidelines model indicated that an increase in the debt ratio from 40% to 50% increased a firm's cost of debt 56 basis points. An increase in the debt ratio from 50% to 60% increased a firm's debt cost 120 basis points.

To estimate the leverage/equity cost relationship in the rating guidelines model, Gapenski used an econometric model to estimate the relationship between a firm's cost of equity and its cost of debt. This was then combined with the leverage/debt cost relationship determined by the rating guidelines model.

The following table summarizes the results from the econometric and bond rating guidelines models:

	Basis Point Change in Debt Cost		**Basis Point Change in Equity Cost**	
Change in Debt Ratio	**Econometric Model**	**Rating Guidelines Model**	**Econometric Model**	**Rating Guidelines Model**
40% to 50%	28	56	74	111
50% to 60%	42	120	113	240

Overall, the results indicate that there is a strong positive relationship between financial leverage and the cost of debt and equity. Specifically, the capital costs/leverage relationship was strongest under the rating guidelines model. Gapenski also concluded that the two most significant risks to debt and equity investors were nuclear construction programs and reserve margins. In contrast to previous studies, regulatory climate did not affect equity or debt costs during the study period (Gapenski, 1986: 8).

There have also been numerous studies that examined the effects of the regulatory environment on the cost of capital. The most prominent was Dubin and Navarro (1982). They examined the cost of capital issue from a different point of view than previous studies. Previous studies had focused on only one component (debt or equity) of a firm's overall cost of capital. Dubin and Navarro (1982) studied how change in the regulatory environment affects the overall cost of capital (that is, the cost of both debt and equity). Furthermore, studies such as Trout (1979) and Archer (1981) suffered major methodological and conceptual problems. These ranged from econometric errors such as model misspecification to the use of an arbitrarily restricted data sample.

The regulatory environment for electric utilities has been observed by various groups and is based upon six objective criteria: (1) allowed rate of return; (2) average regulatory lag; (3) whether a historical or future test year is used; (4) whether construction work in progress (CWIP) is allowed in the rate base or, alternatively, whether an allowance for funds used during construction (AFUDC) is computed; (5) whether the benefits from investment tax credits and accelerated depreciation are "flowed through" or "normalized"; and (6) whether an automatic adjustment clause is in effect[28] (Dubin and Navarro, 1982: 143). A very favorable regulatory environment would include most of the following: a relatively high allowed rate of return; minimal regulatory lag and/or an interim-rate provision; the use of current or future test year; CWIP in rate base; normalization of tax benefits; and, a full automatic fuel-adjustment clause. On the other hand, an unfavorable regulatory environment would include most of the following: a relatively low allowed rate of return; lengthy regulatory lag and/or no interim-rate provision; the use of an historical test year; AFUDC accounting for construction work in progress; flow-through treatment of tax benefits; and, a fuel adjustment clause requiring a hearing or allowing only partial recovery of fuel costs.

Based on these definitions for regulatory environment, Dubin and Navarro examined the effects of the regulatory environment on the cost of capital for the electric industry in 1978. It was concluded that rate-suppressive or unfavorable regulation (from an investor's point of view) raised a utility's cost of capital. Specifically, a change in regulatory environment from favorable to unfavorable, increased the cost of equity capital 228 basis points and resulted in a bond de-rating (for example, from A to B++). Dubin and Navarro (1982: 141-142) concluded that:

> With respect to ratepayers, the adverse effect of an unfavorable regulatory climate on a utility's cost and availability of capital raises an ironic possibility: ostensibly pro consumer policies, which suppress electricity rates in the short run, may actually result in higher medium- and long-run rates. Moreover, consumers may be forced to pay more for less-reliable service.

2.8 STRANDED COST RISK

A characteristic of pipeline investments is that they represent sunk specific investments. A sunk specific investment is where there is an inability to transfer the physical capital to another use or location. Therefore, if a new pipeline by-passes an

[28] Duff and Phelps, Goldman Sachs, Merrill Lynch, Salomon Brothers, and Valueline use these criteria to rate the regulatory environment for the electric industry. These is no known comparable criteria or rating for the natural gas pipeline industry.

existing system, there will be stranded costs in most instances. In the past, there have been relatively few instances of stranded costs in the Canadian natural gas pipeline industry. However, in recent years there have been a number of proposed by-pass pipelines and the Alliance project represents the first major by-pass under NEB jurisdiction. The expected approval of Alliance will almost certainty result in excess capacity and some stranding of pipeline assets. Such approval would also set a precedent for other by-pass proposals and this could set off a chain of events in the Canadian regulatory environment involving a much different allocation of risks.

The major concerns are whether stranded costs will be fully, partially, or not recovered at all, and who will pay these costs. Stranded costs could be allocated to pipeline shareholders, captive customers, or departing customers. For example, a pipeline could charge an exit fee for departing firm service contract holders. However, regulatory agencies such as the FERC, have argued that "a party's contractual obligations should not survive the contract's expiration" (McDonald, 1996: 25). Pipeline companies could adjust rate design to allocate stranded costs to remaining firm service customers. However, such a policy would imply that existing customers pay higher rates for continuing to receive their current level and quality of service. This may conflict with the regulator's objective of "fairness and equity" which, among other things, requires that tolls be "just and reasonable".

With regard to the allocation of stranded costs, the FERC has concluded that in the electric industry these costs are to be recovered by shareholders (FERC, 1996c). In the gas transmission industry, the FERC has typically not required that shareholders fully recover these costs. Instead, customers have been fully responsible for recovering these costs, or shareholders and customers have jointly paid these costs. In the Canadian gas transmission industry, the NEB has not indicated how it would allocate stranded costs if they were to occur. For the purpose of this analysis, it is assumed that all stranded costs will be recovered from pipeline shareholders.

An important policy question addressed in the literature by Kolbe and Borucki (1998), Kolbe and Tye (1998), and Kolbe and Tye (1995), is whether shareholders have already been compensated for stranded cost risk under traditional cost of service regulatory principles. Kolbe and Tye (1998: 1025) explain that:

> The economic principles of asymmetric risk imply that even if investors are fully cognizant of the risks of stranded costs, capital market prices fully reflected such costs, and regulators set the allowed rate of return equal to the true cost of capital, it is mathematically impossible for investors to have been previously compensated for these risks.

The reasoning is simple:

1. according to the automatic compensation theory, the utility expects to earn the cost of capital under unbiased regulation during the period prior to a transition to greater competition;
2. from the definition of stranded costs, the utility expects to earn less than the cost of capital after a transition to greater competition that includes stranded costs;
3. from the law of averages, the average of the rates of return expected on investments prior to the transition (equal to the cost of capital) and the rates of return expected after the transition (less than the cost of capital) is less than the cost of capital;
4. since the utility cannot expect to earn the cost of capital averaged over both good and bad times, the utility's investors (shareholders) cannot have been previously compensated for the risk of stranded costs (Kolbe and Tye, 1996: 1029).

Therefore, to fairly compensate shareholders for stranded cost risks, the rate of return must be set greater than the cost of capital. The difference between the rate of return and the cost of capital is the risk premium that will adequately compensate shareholders. The risk premium is equal to the expected losses arising from stranded costs (i.e., the expected loss if costs are stranded times the probability stranding will occur) (Kolbe and Tye, 1998: 1030). For example, suppose there is a 25% probability that 30% of a pipeline system will be stranded, and the cost of capital is 12.5%. Under the traditional regulatory framework the allowed rate of return would also equal 12.5%. However, if the allowed rate of return is equal to the cost of capital, the weighted average rate of return over both the 'good' (12.5%) and 'bad' (-17.5% = 12.5% - 30%) outcomes is only 5%. The return shareholders expect on average is below the cost of capital. Therefore, shareholders would not have been compensated for the risks they bear. To fully compensate shareholders, the risk premium must equal 7.5% (0.25 x 0.30). Overall, if the overall cost of capital is 12.5% and shareholders are fully compensated for stranded costs, the allowed rate of return should equal 18% (Kolbe and Tye, 1998: 1031).

In summary, the introduction of stranded costs will create considerable complications in risk compensation. If the risk persists for an extended period, the compensation for that risk must also. Since the risk is likely to change from period to period, the required compensation will change from period to period. Since the risk will vary from pipeline to pipeline, the required compensation will vary from pipeline to pipeline (Kolbe and Tye, 1998: 1036). The important point is that the allowed rate of return must be increased enough so that shareholders can expect to earn their cost of capital, given their expected losses from stranded costs. Therefore, the rate of return will not be equal to the cost of capital. The rate of return will be equal to the cost of capital plus a risk premium.

2.9 CONTRIBUTION OF THE THESIS

The focus in this thesis is on how a change in risk exposure would affect the capital structure, cost of capital, and cost of gas transmission for Canadian natural gas pipelines. There is no known study which has examined this issue and the pipeline industry has had little attention in the literature. An examination of the natural gas pipeline industry is useful since most studies dealing with capital structure/cost of capital issues have focused on the U.S. electric industry. Therefore, such a study may provide further insights. For example, the results can provide some insight as to whether changes in the capital structure have a more significant affect in the electric or the gas transmission industry. Furthermore, the focus on the pipeline sector takes advantage of the large variability between the operating conditions in the U.S. and Canada. For example, in Canada the composite tax rate is slightly higher than that in the U.S. and the tight regulation and policies of the NEB have exposed Canadian gas transmission companies to less risk than their U.S. counterparts. This may imply that variations in the capital structure have a greater impact on the cost of capital for companies operating in Canada than they would in the U.S.

Chapter 3 - Analytical Framework

An outline of the analytical framework is presented in this chapter. After the methodology is discussed, there is an explanation and presentation of the non-optimizing spreadsheet/simulation bond rating guidelines model. The chapter concludes with an outline of the various sensitivities and simulations that will be undertaken.

3.1 METHODOLOGY

One of the most important assumptions undertaken throughout the research presented here is that Canadian gas transmission companies will continue to use cost of service pricing methodology regardless of the environment in which they may be operating. One may question whether such an assumption is realistic if the Canadian gas transmission industry shifts from monopoly to competition. For example, it may be inefficient to use cost of service pricing, if transmission companies are trying to find ways to reduce costs in order to provide more competitive rates for customers. However, there are not many costs that transmission companies can significantly reduce. As shown in Table 1.1, the four significant cost categories are: return on rate base; depreciation; operating and maintenance costs; and, taxes. A significant increase in risk exposure is expected to increase the rate of return and hence, the return on the rate base. A shift to competition is not expected to significantly affect a transmission company's revenues. Therefore, taxes will not be reduced. Companies may decrease their future investments which would reduce future depreciation, but this an unlikely scenario if gas pipeline companies want to remain competitive and profitable. Transmission companies may also consider reducing operating and maintenance costs. However, operating and maintenance expenditures account for a small proportion of the revenue requirement (except for ANG). Furthermore, a substantial portion of operating and maintenance costs, certainly more than 70%, is irreducible because these costs are required to maintain minimal reliability and safety standards. Hence, increased operational efficiency is unlikely to have a significant impact on rates (Sherwin and McShane, 1992: 16).

It would also be unfair to change the rules on cost recovery for investments that have already been made and approved under regulation. Therefore, for Canadian gas pipelines to continue to recover their fixed costs, some form of cost of service pricing methodology will have to be maintained. Furthermore, even if pipeline companies were under light-handed regulation, it can be expected that their ratemaking framework would benchmark cost of service regulation. Overall, cost of service pricing methodology appears to be the best alternative for the Canadian gas transmission industry. It has proven itself over the years in the timely provision of transportation services, the quality and reliability of service, the range of services available, and the efficiency of operations. Facilities have been built, pipeline companies have remained financially healthy, and customers have received service (Natural Gas Analyst, 1997a: 7).

One objective of the thesis is to examine a how change in risk exposure would affect the capital structure, cost of capital, and transmission costs for Canadian natural gas pipelines. It was noted in Section 2.6 that the introduction of by-pass and pipe on pipe competition should increase the cost of capital and decrease the debt-to-equity ratio. However, the significance of these changes and the affects on transmission costs and tolls is uncertain. The problem is that the magnitude of the increase in risk exposure is unclear. Furthermore, it is uncertain how shareholders, bond rating agencies, and capital markets will react. To address this problem, a non-optimizing spreadsheet/simulation bond rating guidelines model is developed. The following section explains the methodology.

To demonstrate how changes in the capital structure affect the bond ratings for Canadian natural gas pipelines, the following Canadian Bond Rating Service Utility Financial Benchmarks are used:

TABLE 3.1: CANADIAN BOND RATING SERVICE FINANCIAL BENCHMARKS

Financial Benchmark	A++	A+	A	B++
Common Equity (minimum $ millions)	$250	$150	$100	$50
Debt Leverage	50% and lower	50%-60%	60%-70%	65%-75%
Interest Coverage[29]	4.0x and greater	2.8x-4.0x	1.9x-2.8x	1.6x-2.2x
Cash Flow % Total Debt[30]	25% and greater	15-25%	10%-20%	10%-15%

Source: Canadian Bond Rating Service (1998b).

The bond rating for a pipeline company is determined by calculating the total debt (that is, funded and unfunded) and applying this to the debt leverage ratio financial benchmark as outlined above. As shown in Table A3 (Appendix A), the average bond rating for Canadian gas transmission companies is A(low) since the total debt is in the 60% - 70% range. If the total debt for Canadian gas pipelines were to decrease below 50%, then bond rating agencies such as the CBRS would increase the rating of debt holdings to A++. If the debt leverage were increased above 70%, then the CBRS would downgrade the rating of debt holdings to B++. One also expects that the common equity, interest coverage, and cashflow % total debt benchmarks would change in accordance with the bond rating benchmark for the various debt ratios. Therefore, these financial benchmarks will be ignored in the spreadsheet/simulation analysis.

The next step is to link how changes in bond ratings affect the cost of capital. Instruments commonly used to finance capital are funded debt, unfunded debt,[31]

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[29] Interest coverage is the ability of the company to pay the interest charges on its debt.

$$\text{Interest Coverage} = \frac{\text{Net earnings (before extraordinary items) - equity income + minority interest in earnings of subsidiary companies + all income taxes + total interest charges}}{\text{Total interest charges}}$$

Source: Canadian Securities Course (1996: 3.12)

[30] Cashflow % Total Debt is the ability of the company to repay the funds it has borrowed.

$$\text{Cashflow \% Total Debt} = \frac{\text{Net earnings (before extraordinary items) - equity income + minority interest in earnings of subsidiary companies + deferred income taxes + depreciation + any other deductions not paid out in cash, e.g. depletion, amortization, etc.}}{\text{Total debt outstanding (i.e. short and long-term)}}$$

Source: Canadian Securities Course (1996: 3.10)

[31] See Definitions for an explanation of funded debt and unfunded debt.

debentures, preferred share capital, and common equity. To estimate the affect of leverage on the cost of capital, the CBRS historic ten-year bond yield averages are used to determine the cost of unfunded debt.[32] Based on the data from Table A8 (Appendix A), the calculated spread for ten-year Canadian utility bond yield averages is as follows:

A+ - A	12 basis points
A - B++	15 basis points

The spread for ten-year corporate bond yield averages is as follows:

A++ - A+	2 basis points
A+ - A	14 basis points
A - B++	79 basis points

The data suggests that the greater the level of risk exposure faced by an industry, the greater the required yield on bonds issued by that industry.[33]

To determine the costs for the other capital instruments, the spreads between the various capital instruments and unfunded debt are calculated. The spreads between the capital instruments are calculated from TCPL's 1997 rate application and the decision by the NEB in RH-1-97.

TABLE 3.2: TCPL'S CAPITAL STRUCTURE AND COST RATES FOR THE 1997 TEST YEAR

	Capital Structure (%)	Cost Rate (%)
Funded Debt	54.70	10.09
Unfunded Debt	5.75	6.91
Junior Subordinated Debentures	2.85	8.57
Preferred Share Capital	6.70	7.28
Common Equity	30.00	10.67

Source: National Energy Board (1997b: 10)

[32] Note that there will be some error due to the fact that the bond yield averages are based upon the utility sector as a whole. The Canadian natural gas pipeline industry has bond yield averages that are comparable, but probably not exactly the same.

[33] Note that the calculated spread for ten-year bond yield averages was based on observations from 1996-1998. The spread for ten-year bond yield averages was also calculated separately for 1998, 1997, and 1996. It was concluded that over these time periods the spreads have remained constant.

From the table above, the following spreads are calculated:

funded debt - unfunded debt	318 basis points
junior subordinated debentures - unfunded debt	166 basis points
preferred share capital - unfunded debt	37 basis points
common equity - unfunded debt	376 basis points

To calculate the cost rates for the various capital instruments, first requires the determination of the cost of unfunded debt. Then the respective spreads are applied in order to determine the cost rates for the other capital instruments. For example, the cost of funded debt is equal to the cost of unfunded debt plus the spread between the two instruments (6.91 + 3.18 = 10.09%). If the cost of unfunded debt increased 15 basis points, so the new cost rate was 7.06% (6.91% + .15% = 7.06%), the cost of funded debt would be 10.24% (7.06% + 3.18% = 10.24%). With regard to the cost of common equity, it is equal to the cost of unfunded debt plus the spread between the two instruments (6.91% + 3.76% = 10.67%). If the cost of unfunded debt increased 15 basis points, so the new cost rate was 7.06% (6.91% + .15% = 7.06%), the cost of common equity would be 10.82% (7.06% + 3.76% = 10.82%).

One might question whether the spreads between the various capital instruments change when the capital structure is altered. Gapenski (1987: 8) concluded that there was no evidence that the leverage/capital cost relationships are nonlinear. Recall the following results derived by Gapenski:

	Basis Point Change in Debt Cost		**Basis Point Change in Equity Cost**	
Change in Debt Ratio	**Econometric Model**	**Rating Guidelines Model**	**Econometric Model**	**Rating Guidelines Model**
40% to 50%	28	56	74	111
50% to 60%	42	120	113	240

If one does some very simple calculations, the change in the cost of debt is .67 (.28 ÷ .42), while the change in the cost of equity is .65 (.74 ÷ 1.13) with the econometric model. Under the bond rating guidelines model, the change in the cost of debt is .47 (.56 ÷ 1.20), while the change in the cost of equity is .46 (1.11 ÷ 2.40). Based on these calculations, one could conclude that the spread between capital instruments does not appear to change as the capital structure is varied and this is assumed in the analysis undertaken in this thesis.

Throughout the thesis it is being assumed that the only way to alter the capital structure is to change the amount of funded debt and common equity within the portfolio. The percentage of all other capital instruments in the portfolio are assumed to remain constant. Therefore, the percentage of unfunded debt, junior subordinated debentures, and preferred share capital will remain at 5.75%, 2.85%, and 6.70% respectively.[34] Combining the CBRS financial benchmarks and historic ten-year bond yield averages, the following table outlines the cost of capital if TCPL is allowed to determine its own capital structure within a modest range of the common equity ratio deemed by the NEB.

TABLE 3.3: IMPACT OF LEVERAGE ON THE COST OF CAPITAL[35]

Funded Debt		Bond Rating	Unfunded Debt		Junior Sub. Deb.[36]		Preferred Share		Common Equity		Cost of Capital
Cost	%		Cost	%	Cost	%	Cost	%	Cost	%	
9.97	49.7	A+	6.79	5.75	8.45	2.85	7.16	6.70	10.55	35.00	9.76%
10.09	54.7	A	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.00	9.85%
10.24	59.7	B++	7.06	5.75	8.72	2.85	7.43	6.70	10.82	25.00	9.97%

Table 3.3 indicates that if there was no change in the exposure to risk (that is, business, financial, market, and regulatory risk), but TCPL increased its debt-to-common equity ratio (hence, increase the percentage of funded debt from 54.7% to 60% and decrease the percentage of common equity from 30.0% to 25.0%), the bond rating for TCPL's debt holdings would be downgraded from an A to B++. This results in an increase in the cost of debt and equity since the possibility of financial distress and the risk faced by

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[34] Note that it is not expected that funded debt and common equity would be the only instruments to change in the capital structure portfolio if there is a change in risk exposure. For example, one could expect that the percentage of preferred share capital would decrease. However, to simplify the non-optimizing spreadsheet/simulation analysis, it is being assumed that the only instruments that can be altered are the percentage of funded debt and common equity. This is an area for further research that will be discussed in Section 5.5.

[35] See Appendix B for calculations.

[36] Junior Sub. Deb. is Junior Subordinated Debentures.

shareholders will have increased. Overall, the cost of capital can be expected to increase from 9.85% to approximately 9.97%.

On the other hand, if TCPL were to decrease its debt-to-common equity ratio (hence, decrease the percentage of funded debt from 54.7% to 49.7% and increase the percentage of common equity from 30.0% to 35.0%), the bond rating for TCPL's debt holdings would be upgraded from an A to A+. This results in a decrease in the cost of debt and equity since the possibility of financial distress and the risk faced by shareholders will have decreased. Overall, the cost of capital can be expected to decrease from 9.85% to approximately 9.76%.

There have been numerous empirical studies that have examined the effects of leverage on the cost of equity for the electric industry. Previous studies have examined the effects on the cost of equity if the common equity ratio increased from 40% to 50%. Such an increase in leverage is equivalent to a bond rating change from BBB to AA (based on Standard & Poor's bond ratings). This is comparable to a change in the bond ratings from B++ to A+ (based on CBRS bond ratings), and a change in the common equity ratio from 25% to 35% in the Canadian natural gas pipeline industry.[37] The purpose of this comparison is to determine whether the methodology used in this thesis produces results which are in line with those from previous studies.[38] The following table summarizes the results.

[37] Refer to Table A5 (Appendix A) for bond rating comparisons between CBRS and Standard & Poor's.

[38] That is, when companies change their capital structure, but there is no change in the exposure to risk (that is, business, financial, market, and regulatory risk).

TABLE 3.4: EFFECTS OF LEVERAGE ON THE COST OF COMMON EQUITY: RESULTS FROM OTHER STUDIES

Theoretical Studies	Increase in Equity Cost When the Common Equity Ratio Increases from 40% to 50%
Modigliani and Miller (1958)	115 basis points
Modigliani and Miller (1963)	62
Miller (1977)	237
Average	**138**

Effects of Leverage on Common Equity: Theoretical Studies

Empirical Regression Studies	Result
Brigham and Gordon (1968)	34 basis points
Gordon (1974)	45
Robichek, Higgins, and Kinsman (1973)	75
Mehta, Moses, Deschamps, and Walker (1980)	109
Gapenski (1987)	74
Brigham, Gapenski, and Aberwald (1987)	117
Average	**67**
Bond Rating Guidelines Studies	**Result**
Gapenski (1987)	111
Kruzel (1998)[39]	**27**

Table 3.4 indicates that the impacts here are in fact lower than these previous studies. An explanation for the results is that the electric utility industry has been more risky than the Canadian gas transmission industry. Therefore, the effects of leverage on the cost of equity is more significant in the electric industry since there is greater shareholder risk and probability of financial distress. Another explanation is that the assumptions and proxies that the thesis employs underestimate the actual impact of leverage on the costs of financial capital. Consequently, the results and core implications discussed in the following chapters may be understated.

[39] This calculation is based on a change in the common equity ratio from 25% to 35% in the Canadian gas transmission industry.

3.2 DESCRIPTION OF THE MODEL

The model is a non-optimizing spreadsheet/simulation based upon the bond rating guidelines model used in Gapenski (1987). It employs data and parameters for TCPL using information presented in TCPL's 1997 rate application and NEB decision, RH-1-97. If one wanted to use the model for one of the other Canadian gas pipelines, slight variations would have to be made to the model to account for the different characteristics that exist between pipeline systems.[40] The non-optimizing spreadsheet/simulation bond rating guidelines model consists of two interconnected parts, Part A and B. Part A measures the cost of capital for varying capital structures and levels of risk exposure. Part B deals with TCPL's transportation revenue requirement. Part B also consists of several sub-parts: B1 calculates TCPL's rate base; B2 calculates TCPL's flow-through taxation; and, B3 calculates TCPL's capital structure and cost rates.

The model demonstrates how a change in risk exposure affects the capital structure and the cost of capital for the benchmark pipeline under cost of service tolling methodology. Based upon this information, it calculates the change in the cost of gas transmission. The model works as follows:

1. A change in risk exposure faced by TCPL or a change in the capital structure, will affect the cost of capital in Part A. The larger the increase in risk exposure, the more significant the increase in the cost of capital and decrease in the debt-to-common equity ratio. The different magnitudes of risk exposure will be captured in various sensitivities and simulations that will be undertaken. An outline of the sensitivities and simulations is presented in Section 3.4.
2. A change in the cost of capital and/or capital structure in Part A, will then affect income taxes and the return on the rate base in Part B. The return on the rate base is equal to the allowed rate base multiplied by the cost of capital or the rate of return on the rate base. Traditionally in cost of service regulation, the rate of return on the rate base is equal to the cost of capital. However, if stranded costs are expected, the rate

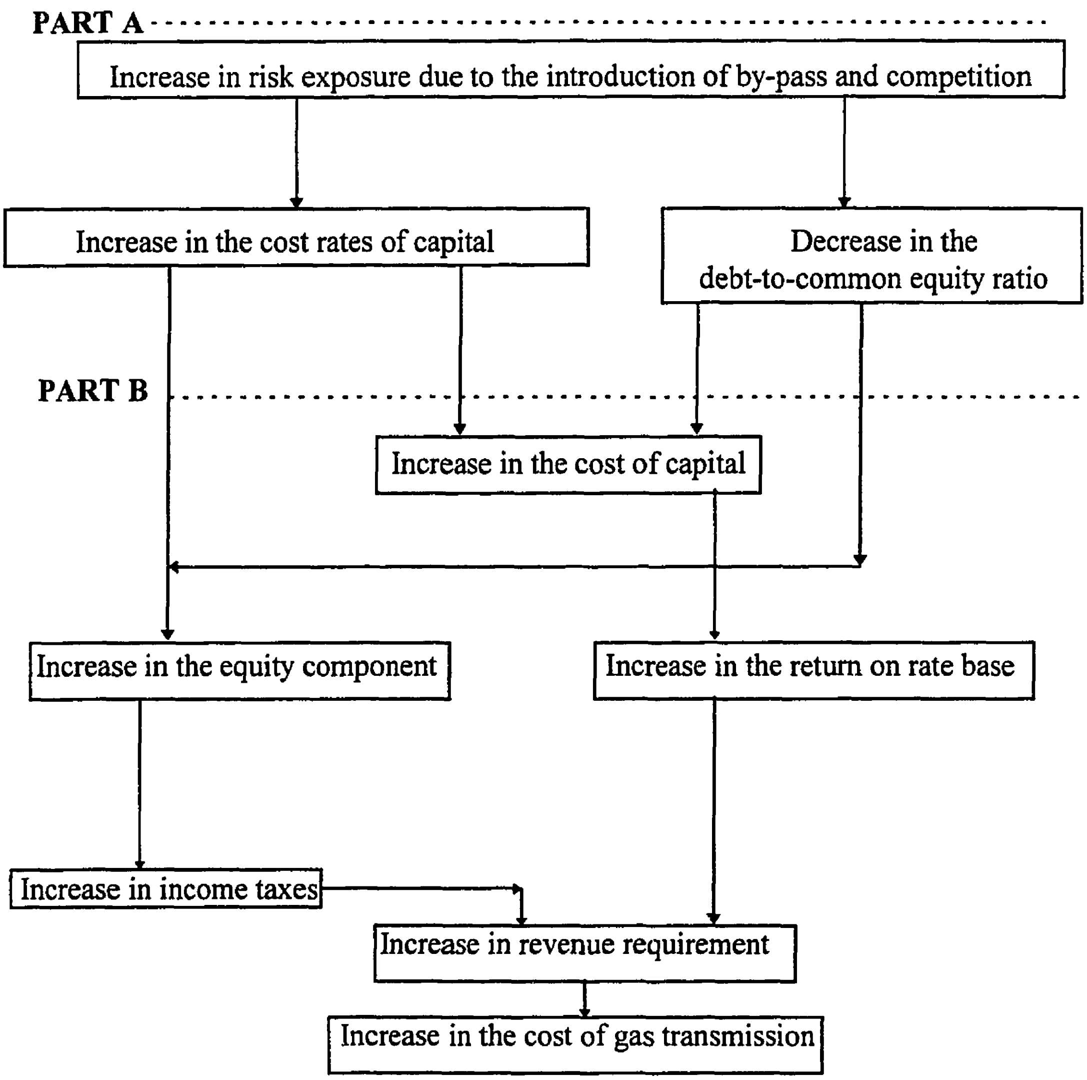
[40] That is, pipeline companies use different taxation schemes such as flow through or normalization, some pipelines have gathering lines and some do not, and so forth.

of return will be equal to the cost of capital plus a risk premium. Income taxes are based upon calculations in Part B3. Specifically, a decrease in the debt-to-common equity ratio and an increase in the cost of capital will increase the equity component. An increase in the equity component will in turn, increase income taxes.

3. A change in income taxes and the return on the rate base in Part B will change the net revenue requirement.
4. An average transmission cost is determined by dividing the net revenue requirement by the length of TCPL's Canadian mainline in 1996. Therefore, a change in the net revenue requirement will in turn, change the average cost of gas transmission.

The following flow-diagram illustrates the process of the model.

DIAGRAM 3.1 THE MODEL PROCESS



3.3 PRESENTATION OF THE MODEL

The following section presents the non-optimizing spreadsheet/simulation bond rating guidelines model which will be used to measure the effects of a change in risk exposure on the capital structure, cost of capital, and cost of gas transmission for Canadian natural gas pipelines. In Part B and the sub-parts for Part B, all bold-italicized input determinants are variable to changes in risk exposure and/or changes in the capital structure. All other input determinants are assumed to remain constant.

MODEL PART A: IMPACT OF LEVERAGE ON THE COST OF CAPITAL[41]

Funded Debt		Bond Rating	Unfunded Debt		Junior Sub. Deb.		Preferred Share		Common Equity		Cost of Capital
Cost	%		Cost	%	Cost	%	Cost	%	Cost	%	
9.97	49.7	A+	6.79	5.75	8.45	2.85	7.16	6.70	10.55	35.0	9.76%
10.09	54.7	A	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.24	59.7	B++	7.06	5.75	8.72	2.85	7.43	6.70	10.82	25.0	9.97%

[41] See Appendix B for calculations. Note that this is an example where TCPL is allowed to determine its own capital structure within a modest range of the common equity ratio deemed by the NEB, and there is no change in risk exposure. Cases where there are increases in risk exposure are discussed in the next section.

MODEL PART B: TCPL'S TRANSPORTATION REVENUE REQUIREMENT FOR THE 1997 TEST YEAR AND THE COST OF TRANSMISSION[42]

Incentive Cost Envelope	$689,839,000
Flow-Through Cost Envelope	
Income Taxes	***102,106,843***
Depreciation	252,230,000
Return on Rate Base	***731,633,101***
Foreign Exchange Cost	2,643,000
Electric Fuel Costs	12,680,000
Insurance Deductible Costs	3,701,000
Stress Corrosion Cracking & Corrosion Control	64,072,000
Sub Total Flow-Through Envelope	1,169,065,945
Regulatory Amortizations	(67,645,000)
Pressure Charges	4,854,000
Gross Revenue Requirement	1,796,113,945
Non-Discretionary Miscellaneous Revenue	(54,115,000)
Discretionary Miscellaneous Revenue	(12,300,000)
Interim Revenue Adjustment	(25,335,000)
Net Revenue Requirement	**$1,704,363,945**
Canadian Mainline Length -1996 (km)	14,274
Average Cost per km	**$119,403.39**

Source: National Energy Board (1997b: 4).

[42] See Appendix B for calculations.

B1: TCPL'S RATE BASE FOR THE 1997 TEST YEAR[43]

Utility Investment	
Gross Plant	9,784,091,000
Accumulated Depreciation	(2,479,335,000)
Net Plant	7,304,756,000
Contributions in Aid of Construction	(2,410,000)
Total Plant	7,302,346,000
Working Capital	
Cash	22,243,000
GST Receivable, Net	2,320,000
Materials & Supplies	43,866,000
Transmission Linepack	39,905,000
Prepayments & Deposits	1,428,000
Total Working Capital	109,762,000
Deferred Costs	
Miscellaneous Deferred Items	37,797,000
Operating & Debt Service Deferrals	(33,211,000)
Surplus Pension	10,450,000
Total Deferred Costs	15,036,000
Total Rate Base	$7,427,144,000

Source: National Energy Board (1997b: 8).

[43] See Appendix B for calculations.

B2: TCPL'S SCHEDULE OF FLOW-THROUGH INCOME TAXES FOR THE 1997 TEST YEAR[44]

***Equity Component*[45]**	***274,061,614***
Depreciation	252,230,000
Large Corporation Tax	18,347,000
Preferred Share Dividend Tax	215,000
Non-Allowed Amortization of Debt Discount & Expense and Foreign Exchange Costs	5,708,000
Non-Allowed Expenses	(1,057,000)
Capital Cost Allowance	(413,533,000)
Benefits Capitalized	(3,281,000)
Eligible Capital Expenses	(70,000)
Interest AFUDC[46]	(14,177,000)
North Bay Litigation Costs	(4,768,000)
Issue Costs	(6,287,000)
Taxable Income	
Taxes at 0.43756 ÷ (1-0.43756) x Taxable Income	83,544,843
Recovery of Large Corporation Tax	18,347,000
Income Tax on Preferred Share Dividends	215,000
Utility Income Tax Requirement	**$102,106,843**

Source: National Energy Board (1997b: 29).

[44] See Appendix B for calculations.
[45] Equity component equals the allowed rate base multiplied by the allowed weighted average costs of preferred and common equity.
[46] AFUDC is allowance for funds used during construction.

B3: TCPL'S DEEMED CAPITAL STRUCTURE AND RATES OF RETURN FOR THE 1997 TEST YEAR[47]

	Amount	Capital Structure	Cost Rate	Cost Component
Funded Debt	4,182,574,000	*54.70%*	*10.09%*	5.52%
Unfunded Debt	439,136,000	5.75%	*6.91%*	0.40%
Total Debt Capital	4,621,710,000	60.45%		
Junior Subordinated Debentures	218,082,000	2.85%	*8.57%*	0.24%
Preferred Share Capital	512,649,000	6.70%	*7.28%*	0.49%
Common Equity	2,293,903,000	*30.00%*	*10.67%*	3.20%
Total Capitalization	7,646,344,000[48]	100.00%		
Rate of Return				*9.85%*

Source: National Energy Board (1997b: 10)

[47] See Appendix B for calculations.

[48] Rate Base $7,427,144 + GPUC $219,200 = Total Capitalization $7,646,344. GPUC is gross plant under construction.

3.4 OUTLINE OF THE VARIOUS SENSITIVITIES AND SIMULATIONS TO BE TESTED

The most significant problem that exists when one tries to measure the effects of a change in risk exposure, due to the introduction of by-pass and pipe on pipe competition, is that there are no previous examples from the industry to base the conclusions upon. An increase in risk exposure, due to the introduction of by-pass and pipe on pipe competition, will increase the cost of capital and decrease the debt-to-equity ratio, but by how much is uncertain. The significance of the changes depends on the increase in risk exposure and the reaction of shareholders, bond rating agencies, and capital markets. To address this problem, a non-optimizing model is employed that uses various sensitivities and simulations to capture the most likely scenarios and reactions.

Several sensitivities will be used in the thesis to capture the different degrees of reaction from shareholders. There are three different levels of sensitivities for an A and B++ bond rating: low sensitivity, medium sensitivity, and high sensitivity. The sensitivities are based on the current spreads between utility and corporate bond yields. The spread between utility and corporate bond yields are a proxy for changes in the costs of capital for a utility under riskier conditions. All three sensitivities will be tested for each simulation and for an A and B++ bond rating. The sensitivities will be tested for an A and B++ bond rating since the future bond rating for Canadian natural gas pipelines is uncertain. Sensitivities for the A and B++ bond rating are defined as follows:

LOW SENSITIVITY (A): is where the cost of unfunded debt does not change from the current state. Therefore, it is assumed that the cost of unfunded debt remains at 6.91%. The overall cost of capital will be as follows for the various capital structures:[49]

[49] Refer to Appendix B for all sensitivity calculations.

Funded Debt Cost	%	Unfunded Debt Cost	%	Junior Sub. Deb. Cost	%	Preferred Share Cost	%	Common Equity Cost	%	Cost of Capital
10.09	54.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.09	49.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	35.0	9.88%
10.09	39.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	45.0	9.94%
10.09	29.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	55.0	9.99%

MEDIUM SENSITIVITY (A): is where the cost of unfunded debt increases 5 basis points. This is halfway between the current spread of utility and corporate rated bond yields with a rating of A. Under Medium Sensitivity (A), the cost of unfunded debt increases from 6.91% to 6.96%. The overall cost of capital will be as follows for the various capital structures:

Funded Debt Cost	%	Unfunded Debt Cost	%	Junior Sub. Deb. Cost	%	Preferred Share Cost	%	Common Equity Cost	%	Cost of Capital
10.09	54.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.14	49.7	6.96	5.75	8.62	2.85	7.33	6.70	10.72	35.0	9.93%
10.14	39.7	6.96	5.75	8.62	2.85	7.33	6.70	10.72	45.0	9.99%
10.14	29.7	6.96	5.75	8.62	2.85	7.33	6.70	10.72	55.0	10.04%

HIGH SENSITIVITY (A): is where the cost of unfunded debt increases 10 basis points. This is the current spread between utility and corporate bond yields with an A rating. Under High Sensitivity (A), the cost of unfunded debt increases from 6.91% to 7.41%. The overall cost of capital will be as follows for the various capital structures:

Funded Debt Cost	%	Unfunded Debt Cost	%	Junior Sub. Deb. Cost	%	Preferred Share Cost	%	Common Equity Cost	%	Cost of Capital
10.09	54.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.19	49.7	7.01	5.75	8.67	2.85	7.38	6.70	10.77	35.0	9.98%
10.19	39.7	7.01	5.75	8.67	2.85	7.38	6.70	10.77	45.0	10.04%
10.19	29.7	7.01	5.75	8.67	2.85	7.38	6.70	10.77	55.0	10.09%

LOW SENSITIVITY (B++): is where the cost of unfunded debt increases 15 basis points. This is the current spread between A and B++ rated bonds for utilities. Under Low Sensitivity (B++), the cost of unfunded debt increases from 6.91% to 7.06%. The overall cost of capital will be as follows for the various capital structures:

Funded Debt Cost	%	Unfunded Debt Cost	%	Junior Sub. Deb. Cost	%	Preferred Share Cost	%	Common Equity Cost	%	Cost of Capital
10.09	54.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.24	54.7	7.06	5.75	8.72	2.85	7.43	6.70	10.82	30.0	10.00%
10.24	49.7	7.06	5.75	8.72	2.85	7.43	6.70	10.82	35.0	10.03%
10.24	39.7	7.06	5.75	8.72	2.85	7.43	6.70	10.82	45.0	10.09%

MEDIUM SENSITIVITY (B++): is where the cost of unfunded debt increases 50 basis points. This is halfway between the spread of utility and corporate bond yields with a B++ rating. Under Medium Sensitivity (B++), the overall cost of capital will be as follows for the various capital structures:

Funded Debt Cost	%	Unfunded Debt Cost	%	Junior Sub. Deb. Cost	%	Preferred Share Cost	%	Common Equity Cost	%	Cost of Capital
10.09	54.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.59	54.7	7.41	5.75	9.07	2.85	7.78	6.70	11.17	30.0	10.35%
10.59	49.7	7.41	5.75	9.07	2.85	7.78	6.70	11.17	35.0	10.38%
10.59	39.7	7.41	5.75	9.07	2.85	7.78	6.70	11.17	45.0	10.44%

HIGH SENSITIVITY (B++): is where the cost of unfunded debt increases 85 basis points. This is the current spread between utility and corporate bond yields with a B++ rating. Under High Sensitivity (B++), the cost of unfunded debt increases from 6.91% to 7.76%. The overall cost of capital will be as follows for the various capital structures:

Funded Debt		Unfunded Debt		Junior Sub. Deb.		Preferred Share		Common Equity		Cost of Capital
Cost	%	Cost	%	Cost	%	Cost	%	Cost	%	
10.09	54.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.94	54.7	7.76	5.75	9.42	2.85	8.13	6.70	11.52	30.0	10.70%
10.94	49.7	7.76	5.75	9.42	2.85	8.13	6.70	11.52	35.0	10.73%
10.94	39.7	7.76	5.75	9.42	2.85	8.13	6.70	11.52	45.0	10.79%

Various simulations are employed to capture different increases in risk exposure that could face pipelines and their shareholders. Specifically, the simulations will be based upon capital structures and stranded costs that may result due to the introduction of by-pass and pipe on pipe competition. There are four simulation sets, I-IV. Each simulation set represents a different level that the capital structure may adjust to. The more significant the decrease in the debt-to-common equity ratio, the larger the increase in risk exposure. The simulations sets are defined as follows:

SIMULATION SET I: Under this scenario there is no change in the risk exposure (that is, business, financial, market, and regulatory risk) faced by the Canadian gas transmission industry, no stranded costs, and the regulatory environment remains unchanged. However, gas pipelines are now able to determine their own capital structure within a modest range of the common equity ratio deemed by the NEB. The model is simulated for an A+ and B++ bond rating. Based upon the results, it will be possible to assess whether gas transmission companies should be able to determine their own capital structure. Here the focus is on whether slight variations in capital structure affect the cost of capital and the cost of gas transmission. For this set of simulations the debt leverage benchmark ratios are:

Debt Leverage Ratio	Bond Rating
50% - 60%	A+
60% - 70%	A
65% - 75%	B++

SIMULATION SET II: In this case there is a change in risk exposure faced by Canadian gas pipelines. Bond rating agencies react by adjusting the debt leverage benchmark ratios. For this set of simulations the debt leverage benchmark ratios are:

Debt Leverage Ratio	Bond Rating
50%-60%	A
60%-70%	B++

For simulation II the capital structure for A rated bonds is adjusted, but the capital structure for B++ rated bonds is equal to the current capital structure. Furthermore, the debt leverage benchmark ratios are those that are currently used by the CBRS for Canadian oil pipelines. Overall, this is equivalent to decreasing the current debt leverage benchmarks by 10%.

SIMULATION SET III: Under this scenario there is also a change in risk exposure faced by Canadian gas pipelines. Bond rating agencies react by adjusting the debt leverage benchmark ratios. For this set of simulations the debt leverage benchmark ratios are:

Debt Leverage Ratio	Bond Rating
40%-50%	A
50%-60%	B++

Overall, this is equivalent to decreasing the current debt leverage benchmarks by 20%. This is slightly over halfway between the current Canadian and U.S. debt leverage ratio benchmarks.

SIMULATION SET IV: Here there is a further change in risk exposure faced by Canadian gas transmission companies. Bond rating agencies react by adjusting the debt leverage benchmark ratios. For this set of simulations the debt leverage benchmark ratios are:

Debt Leverage Ratio	Bond Rating
30%-40%	A
40%-50%	B++

Overall, this is equivalent to decreasing the current debt leverage benchmarks approximately 30%. This is approximately the debt leverage ratios currently observed in the U.S. gas transmission industry.[50]

In each simulation set (except Simulation Set I) five simulations are undertaken. Each simulation represents a possible risk premium that may be expected to adequately compensate shareholders for potential stranded costs. These range from a risk premium of zero to 11.25%. Simulations A-E are defined as follows:

SIMULATION A: There is a zero probability of stranded costs. Therefore, there is no risk premium required to compensate shareholders for the possibility of stranded costs.

SIMULATION B: There is some combination where the probability and magnitude of stranded costs requires a risk premium of 250 basis points. For example, a 50% probability that 5% of the system will be stranded. Therefore, to fairly compensate shareholders the rate of return on the rate base will be 250 basis points greater than the cost of capital.

SIMULATION C: There is some combination where the probability and magnitude of stranded costs requires a risk premium of 500 basis points. For example, a 50% probability that 10% of the system will be stranded. Therefore, to fairly compensate shareholders the rate of return on the rate base will be 500 basis points greater than the cost of capital.

SIMULATION D: There is some combination where the probability and magnitude of stranded costs requires a risk premium of 750 basis points. For example, a 75% probability that 10% of the system will be stranded. Therefore, to fairly compensate shareholders the rate of return on the rate base will be 750 basis points greater than the cost of capital.

SIMULATION E: There is some combination where the probability and magnitude of stranded costs requires a risk premium of 1125 basis points. For example, a 75% probability that 15% of the system will be stranded. Therefore, to fairly compensate

[50] Even if the risk exposure was similar between U.S. and Canadian gas pipelines, one would expect Canadian gas transmission companies to have a slightly higher debt-to-equity ratio due to the greater interest tax shield that is available.

shareholders the rate of return on the rate base is to be 1125 basis points greater than the cost of capital.

In summary, an increase in risk exposure, due to the introduction of by-pass and pipe on pipe competition, is expected to negatively affect the capital structure, cost of capital, and cost of gas transmission for Canadian gas transmission companies. However, the significance of these affects depends on the increase in risk exposure and the reaction of shareholders, bond rating agencies, and capital markets. Therefore, the thesis employs a non-optimizing spreadsheet/simulation model based on bond rating guidelines to capture the most likely scenarios and reactions.

Chapter 4 - Results and Most Likely Scenarios

This section outlines the results and most likely scenarios from the sensitivities and simulations that were undertaken with the non-optimizing spreadsheet/simulation bond rating guidelines model. A summary and discussion of the results from Simulation Sets I-IV is presented in Section 4.1. The complete results are presented in Appendix C. Section 4.2 discusses the most likely scenarios in the short run and long run.

4.1 SUMMARY OF RESULTS

In Simulation I the objective was to determine whether modest changes in the capital structure significantly affects the cost of capital and cost of gas transmission for Canadian natural gas pipelines. Under this scenario the debt-to-common equity ratio of the benchmark pipeline, TCPL, was adjusted for an A+ and B++ bond rating. The changes in capital structure are not due to a change in the exposure of risk (that is, business, financial, market, and regulatory risk). The level of risk exposure is assumed to be unchanged from the current state. However, gas transmission companies are now able to determine their own capital structure within a modest range of the common equity ratio deemed by the NEB.

For an A+ bond rating, the common equity ratio was increased from 30% to 35% and the funded debt ratio was decreased from 54.7% to 49.7%. Therefore, the total debt ratio decreased from 60.45% to 55.45% and the debt-to-common equity ratio decreased from approximately 60%:30% to 55%:35%.[51] For a bond rating of B++, the common equity ratio was decreased from 30% to 25% and the funded debt ratio was increased from 54.7% to 59.7%. Therefore, the total debt ratio increased from 60.45% to 65.45% and the debt-to-common equity ratio increased from approximately 60%:30% to 65%:25%.

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[51] Recall that it is being assumed that the only way to alter the capital structure is to change the amount of funded debt and common equity within the portfolio. The percentage of all other capital instruments in the portfolio are assumed to remain constant. Therefore, the percentage of unfunded debt, junior subordinated debentures, and preferred share capital will remain at 5.75%, 2.85%, and 6.70% respectively.

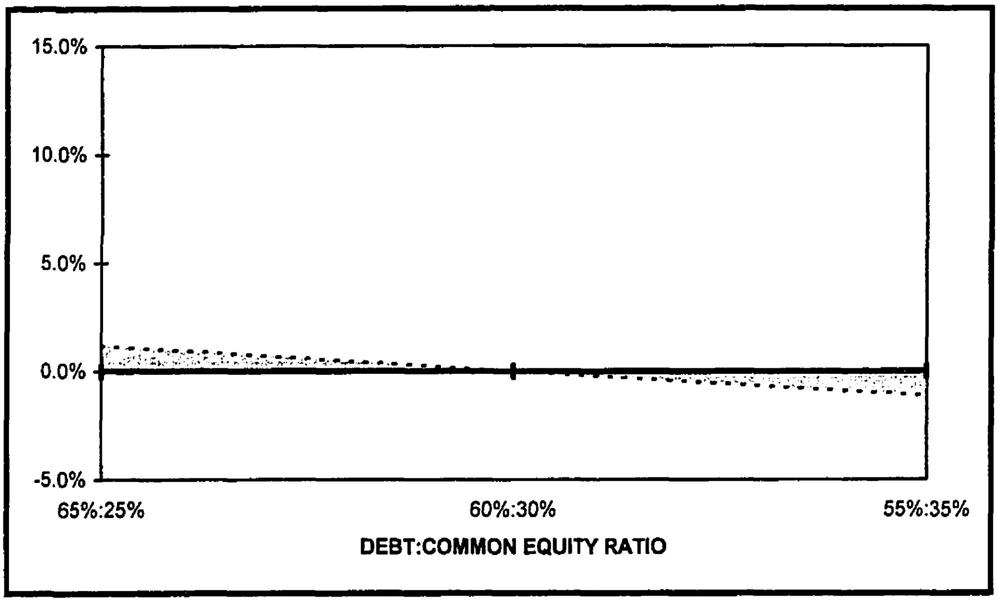
As debt was substituted for equity and the bond rating increased from an A to A+, the transmission costs increased 1.20%. This result is interesting since a decrease in the debt-to-common equity ratio resulted in the cost of capital decreasing from 9.85% to 9.76%. On the other hand, as equity was substituted for debt and the bond rating decreased from an A to B++, the cost of gas transmission decreased 1.13%. This result is also interesting since the cost of capital increased from 9.85% to 9.97% as the debt-to-common equity ratio increased.

Overall, the results indicate that if Canadian gas transmission companies are allowed to determine their own capital structure within a modest range of the common equity ratio deemed by the NEB, transmission costs could change by a maximum of about 2% from what they otherwise might be. Figure 4.1 illustrates that if the benchmark pipeline maintained its deemed 60%:30% debt-to-common equity ratio and A bond rating, there would be no change in transmission costs. However, if the debt-to-common equity ratio increased to 65%:25% and the bond rating was downgraded from an A to B++, the cost of as transmission would be slightly higher from what it otherwise might be. On the other hand, if the debt-to-common equity ratio decreased to 55%:35% and the bond rating was upgraded from an A to A+, the cost of gas transmission would be negligibly lower from what it otherwise might be. With regard to the impact on tolls, a 2% change in the cost of gas transmission would change the average toll by approximately \$0.005/Mcf.[52] Therefore, allowing Canadian gas pipelines to determine their own capital structure within a modest range of the common equity ratio deemed by the NEB, does not appear to have a significant impact on the cost of gas transmission or tolls. Furthermore, the results indicate that a change in leverage has a greater impact on income taxes than on the return on the rate base. For example, an increase in the debt-to-common equity ratio resulted in the cost of capital increasing, but the cost of gas transmission decreasing. The research presented here has assumed that a change in capital structure will only impact the income tax and return on rate base determinants

[52] Refer to Appendix D for toll calculation. Note that this and all other toll calculations assume that the pipeline is able to maintain its current utilization rate which is approximately 95%. Such an assumption is highly unlikely if there is an increase in risk exposure, due to by-pass and pipe on pipe competition, but will be discussed further in Section 5.4.

under the cost of serving pricing methodology. Therefore, the results must imply that a change in the debt-to-common equity ratio is more significant on income taxes than on the return on the rate base.

FIGURE 4.1: PERCENTAGE CHANGE IN THE COST OF GAS TRANSMISSION: PIPELINES ARE ALLOWED TO DETERMINE THEIR OWN CAPITAL STRUCTURE[53]



Simulation Sets II through IV demonstrated how changes in capital structure due to an increase in risk exposure, affected the cost of gas transmission. The simulation sets differed in that each represented a different magnitude of risk exposure that may impact the Canadian gas transmission industry. Therefore, the larger the increase in risk exposure, the more significant the decrease in the debt-to-common equity ratio. Within each simulation set five simulations were undertaken. Each simulation represented a different risk premium that may be expected to adequately compensate investors for recovering stranded costs.

Simulation Set II represented the case where an increase in risk exposure caused the capital structure for Canadian gas pipelines to adjust to those currently used by Canadian oil pipelines. Under such conditions the risk exposure faced by natural gas pipelines would be comparable to that faced by oil pipelines. For an A bond rating, the

[53] That is, within a modest range of the common equity ratio deemed by the NEB.

common equity ratio was increased from 30% to 35% and the funded debt ratio was decreased from 54.7% to 49.7%. Therefore, the total debt ratio decreased from 60.45% to 55.45% and the debt-to-common equity ratio declined from approximately 60%:30% to 55%:35%. For a bond rating of B++, the common equity ratio and the funded debt ratio remained at 30% and 54.7% respectively. Therefore, the total debt and debt-to-common equity ratios remained unchanged from the current state.

The results indicate that if there are no stranded costs expected (Simulation II-A), the cost of gas transmission increased from a low of 0.83% (Low Sensitivity "B++") to a high of 4.54% (High Sensitivity "B++"). On the other hand, if stranded costs are expected, the cost of transmission increased from a low of 10.50% (Low Sensitivity (B++) - Simulation II-B) to a high of 34.97% (High Sensitivity (B++) - Simulation II-E). Overall, if an increase in risk exposure causes gas pipelines to decrease their debt-to-equity ratios to that currently used by Canadian oil pipelines, the cost of gas transmission and tolls could be greatly affected. Under such conditions, the cost of gas transmission could increase from 0.83% to 34.97%. The more significant the risk premium required to adequately compensate shareholders, the greater the increase in the cost of gas transmission.

Simulation Set III represented the case where an increase in risk exposure caused the capital structure to adjust approximately halfway between that currently used by Canadian and U.S. gas pipelines. Under such conditions, the risk exposure faced by Canadian gas pipelines would be greater than the current state, but less than that of U.S. gas pipelines. For an A bond rating, the common equity ratio was increased from 30% to 45% and the funded debt ratio was decreased from 54.7% to 39.7%. Therefore, the total debt ratio decreased from 60.45% to 45.45% and the debt-to-common equity ratio declined from approximately 60%:30% to 45%:45%. For a bond rating of B++, the common equity ratio was increased from 30% to 35% and the funded debt ratio was increased from 54.7% to 49.7%. Therefore, the total debt ratio decreased from 60.45% to 55.45% and the debt-to-common equity ratio declined from approximately 60%:30% to 55%:35%.

If there are no stranded costs expected (Simulation III-A), the cost of gas transmission increased from a low of 2.74% (Low Sensitivity (B++)) to a high of 6.39% (High Sensitivity "B++" - Simulation II-A). On the other hand, if stranded costs are expected, the cost of gas transmission increased from a low of 12.06% (Low Sensitivity "B++" - Simulation III-B) to a high of 35.84% (High Sensitivity "B++" - Simulation III-E). Overall, if an increase in risk exposure causes gas pipelines to decrease their debt-to-equity ratio approximately half way between the debt-to-equity ratios currently employed by Canadian and U.S. gas pipelines, the cost of gas transmission and tolls could be greatly affected. Under such conditions, the cost of gas transmission could increase from 2.74% to 35.84%.

Simulation Set IV represented the case where an increase in risk exposure caused Canadian gas transmission companies to adjust their capital structure approximately to those currently used by U.S. gas pipelines. Under such conditions, the risk exposure faced by Canadian gas pipelines would be similar to that of their U.S. counterparts. For an A bond rating, the common equity ratio was increased from 30% to 55% and the funded debt ratio was decreased from 54.7% to 29.7%. Therefore, the total debt ratio decreased from 60.45% to 35.45% and the debt-to-common equity ratio declined from approximately 60%:30% to 35%:55%. For a bond rating of B++, the common equity ratio was increased from 30% to 45% and the funded debt ratio was increased from 54.7% to 39.7%. Therefore, the total debt ratio increased from 60.45% to 45.45% and the debt-to-common equity ratio declined from approximately 60%:30% to 45%:45%.

The results indicate that if there are no stranded costs expected (Simulation IV-A), the cost of transmission increased from a low of 6.31% (Low Sensitivity "B++") to a high of 9.91% (High Sensitivity "B++"). On the other hand, if stranded costs are expected, the cost of transmission increased from a low of 14.99% (Low Sensitivity "B++" - Simulation II-B) to a high of 37.51% (High Sensitivity "B++" - Simulation II-E). Overall, if an increase in risk exposure causes Canadian gas pipelines to decrease their debt-to-equity ratio approximately to those currently employed by their U.S. counterparts, transmission costs and tolls could be greatly affected. Under such conditions, the cost of gas transmission could increase from 6.31% to 37.51%. A comparison of these results with Simulations Sets II and III leads one to conclude that the more significant the decline in the debt-to-equity ratio, the greater the impact on transmission costs.

In summary, the results indicate that a decline in the capital structure due to an increase in risk exposure, could greatly affect the cost of gas transmission and customer rates. The significance of these affects is dependent on the size of the increase in risk exposure, the reactions of shareholders, bond rating agencies, and capital markets, and whether stranded costs are expected. Table 4.1 summarizes the results from Simulation Sets II-IV. If there are no stranded costs expected, the results indicated that the cost of gas transmission would increase less than 10%. On the other hand, if stranded costs are expected, the cost of gas transmission can be expected to increase by at least 10%. Overall, the more significant the decline in the debt-to-equity ratio and/or the greater the risk premium required to compensate shareholders for recovering stranded costs, the greater the impact on transmission costs.

TABLE 4.1: PERCENTAGE CHANGE IN THE COST OF GAS TRANSMISSION

	Simulation Set II		**Simulation Set III**		**Simulation Set IV**	
	Low	High	Low	High	Low	High
No Stranded Costs	0.83%	4.54%	2.74%	6.39%	6.31%	9.91%
Stranded Costs	10.50%	34.97%	12.06%	35.84%	14.99%	37.51%

With regard to the other Canadian gas pipelines, the impact of a change in capital structure due to an increase in risk exposure, is largely dependent upon the percentage of capital costs relative to total costs. As shown in Table 1.1, the cost of capital as a percentage of total costs for Westcoast is similar to that of the benchmark pipeline. Therefore, the results presented here would be comparable for Westcoast. For ANG, the cost of capital as a percentage of total costs is significantly lower than that of the benchmark pipeline. Therefore, one would expect the results of the benchmark pipeline to overestimate those for ANG. On the other hand, the cost of capital as a percentage of total costs for Foothills and TQM is slightly higher than that of the benchmark pipeline. Therefore, the results for the benchmark pipeline would underestimate those for Foothills and TQM.

4.2 MOST LIKELY SCENARIOS: SHORT RUN & LONG RUN

This section examines the most likely scenarios for the Canadian gas transmission industry in the short run and long run. The short run is an evaluation of the industry in the next five years. This time period can be characterized as a transition phase where mechanisms will be developed and implemented so the industry can move towards complete pipe on pipe competition. The long run is an evaluation of the industry in the next five to ten years. During this time period, the industry should have transformed from monopoly to competition.

In the short run, the NEB can be expected to introduce policies and decisions that encourage pipe on pipe competition and by-pass within the Canadian gas transmission industry. The result of this will be a loss of market share, an increase in the equity risk premium for Canadian gas pipelines, a shift in existing risk from transmission customers to shareholders, and an increase in the overall level of risk exposure for the industry. Large customers can be expected to react to this new environment by evaluating how they can obtain access to cheaper gas. This includes: lengthy negotiations developing between pipeline companies and their customers concerning rate design; customers negotiating with other transmission systems for competitive rates; and, customers examining whether they should build their own by-pass to access cheaper rates. In response, pipeline companies will have to reevaluate how pipe on pipe competition and by-pass would affect their rate design, future investments and expansions, and profitability.

With regard to capital structure, the increase in risk exposure for the Canadian gas transmission industry is expected to decrease the current debt-to-equity ratios used by Canadian gas pipelines, but not to the level currently used by their U.S. counterparts. Furthermore, the financial departments of gas transmission companies will have limited options to adjust their capital structure in the short run. For example, the current percentage of unfunded debt in the capital structure portfolio for TCPL is approximately

6%. Therefore, Canadian gas pipelines can be expected to decrease their debt-to-equity ratio 5% to 10% in the short run. Under such conditions, the most likely scenario appears to be that the short run expectations be based on the results from Simulation Set II. Simulation Set II is where the capital structure of Canadian gas transmission companies adjusts to that currently used by Canadian oil pipelines.

In the short run, the impact of a change in risk exposure on the cost of gas transmission and tolls is dependent on which sensitivity case and risk premium for stranded costs is expected. The low sensitivity cases for an A and B++ bond rating do not appear to be likely. These would imply that the equity risk premium is unchanged from the current state. The introduction of by-pass and pipe on pipe competition will definitely affect the equity risk premium for Canadian gas pipelines. Therefore, the low sensitivities can be ruled out. The high sensitivity cases for an A and B++ bond rating also do not appear to be likely. These sensitivities imply that the increase in risk exposure would cause the equity risk premium for Canadian gas pipelines to be comparable to an average Canadian corporation. It is true that the introduction of by-pass and pipe on pipe competition will increase the risk exposure for Canadian pipelines. However, the frequency of by-pass and the magnitude of pipe on pipe competition is expected to be minimal, at least in the short run. Therefore, the equity risk premium is not expected to increase to such an extent in the transition phase.

In the short run, the most likely scenario appears to be the medium sensitivity under Simulation Set II. Medium Sensitivity (A) is where there is an increase of 5 basis points in the costs of financial capital. On the other hand, Medium Sensitivity (B++) is where there is an increase of 50 basis points in the costs of financial capital. The impact on transmission costs is dependent on the probability and magnitude of expected stranded costs. Once the Alliance pipeline proposal has been approved, a precedent will be set for by-pass in the Canadian gas transmission industry. Under such conditions, the frequency of by-pass and the degree of pipe on pipe competition can be expected to increase. However, the probability and magnitude of stranded costs is expected to be minimal in the next five years. Therefore, it is assumed that there is a 50% probability that 5% of a pipeline system is expected to be stranded, or in other words, a risk premium of 250 basis points is required to adequately compensate shareholders.[54] Under such circumstances the cost of gas transmission would increase 11.59% for an A bond rating and 12.03% for a bond rating of B++. Assuming that one of the objectives for a pipelines company is to minimize the cost of gas transmission,[55] Canadian gas pipelines can be expected to attempt to maintain a bond rating of A.

Overall, based on the non-optimizing spreadsheet/simulation model, the Canadian gas transmission industry can be expected to display the following characteristics in the short run: the debt-to-common equity ratio will decrease from approximately 60%:30% to 55%:35%; the cost of capital will increase approximately from 9.85% to 9.93%; the cost of gas transmission will increase approximately 11%; and, the average toll can be expected to increase approximately $0.0245/Mcf.[56] Therefore, in the short run the degree of pipe on pipe competition and the frequency of by-pass may be minimal, but the impact on the cost of gas transmission and tolls will be significant.

In the long run, the degree of pipe on pipe competition and the frequency of by-pass can be expected to continue to increase. Therefore, the risk exposure faced by the Canadian gas transmission industry will increase even further. Canadian gas transmission companies can expect to face an exposure to risk which is comparable to that currently faced by U.S. gas pipelines. With regard to capital structure, the financial departments of gas transmission companies will have more options to adjust their capital structures in order to minimize the cost of capital in the long run. Therefore, the most likely scenario appears to be that the long run expectations be based on the results from Simulation Set IV. Simulation Set IV is where an increase in risk exposure causes Canadian gas pipeline companies to adjust their capital structure approximately to that currently used by their U.S. counterparts.

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[54] Note that this is a general case intended to hypothesize the impact of stranded costs. Some pipeline systems may expect a greater probability or magnitude of stranded costs and others, less.

[55] Pipeline companies will be expected to minimize their cost of gas transmission in order to provide competitive rates.

[56] Refer to Appendix D for toll calculation.

The impact on transmission costs is dependent on which sensitivity case and risk premium for stranded costs are expected in the long run. The low sensitivities are not likely as this would imply that the equity risk premium is unchanged from the current state. Furthermore, the medium sensitivities are not likely as this would imply that the equity risk premium is unchanged from the short run. In the long run, the most likely scenario appears to be the high sensitivity under Simulation Set IV. High Sensitivity (A) is where the costs of financial capital increase 10 basis points from the current state and 5 basis points from the short run. High Sensitivity (B++) is where the costs of financial capital increase 85 basis points from the current state and 35 basis points from the short run. If one continues to assume that there is a 50% probability that 5% of a pipeline system is expected to be stranded, the transmission costs will increase 17.24% for an A bond rating and 16.50% for a bond rating of B++.[57] Assuming that one of the objectives of a pipeline company is to minimize the cost of gas transmission, the bond rating for Canadian pipeline companies is expected to be downgraded from an A to B++.

Overall, based on the non-optimizing spreadsheet/simulation model, the Canadian gas transmission industry can be expected to display the following characteristics in the next five to ten years: the debt-to-common equity ratio will decrease from 60%:30% in the current state to 45%:45% or from 55%:35% in the short run to 45%:45%; the cost of capital will increase from 9.85% in the current state to 10.79% or from 9.93% in the short run to 10.79%; the cost of gas transmission will increase approximately 5% from the short run or 16.50% from the current state; and, the average toll can be expected to increase approximately $0.015/Mcf from the short run or $0.0395/Mcf from the current state.[58] Therefore, as the degree of pipe on pipe competition and the frequency of by-pass continues to increase, the affect on transmission costs and tolls will become more significant. Under such conditions, the results are irreversible and could cause serious implications for the Canadian gas transmission industry.

[57] For all simulations in Simulation Set IV, transmission costs were minimized if the benchmark pipeline allowed its bond rating to be downgraded from an A to B++.
[58] Refer to Appendix D for toll calculation.

Chapter 5 - Summary, Conclusions, and Areas Of Further Research

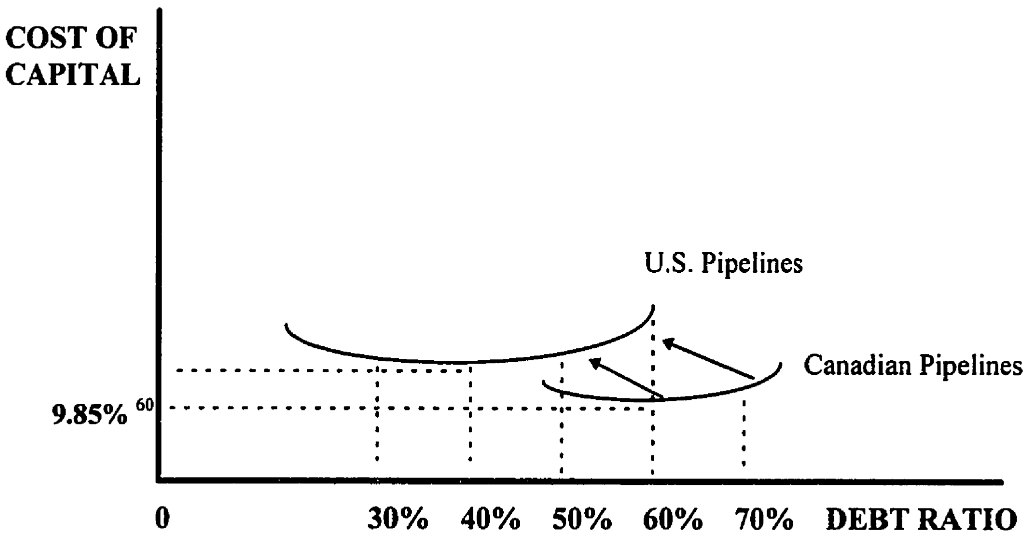
This section presents the summary, conclusions, and areas of further research. Section 5.1 summarizes the research presented here and highlights the main conclusions. A discussion of the core implications is presented in Section 5.2. After this, the relevance of the research and its results is discussed. The chapter concludes with an outline of the areas of further research.

5.1 SUMMARY AND CONCLUSIONS

The single most important cost in the Canadian gas transmission industry is the cost of financial capital. Under the current regulatory framework, the NEB has protected the monopoly position of Canadian gas transmission companies by discouraging by-pass and pipe on pipe competition. This has allowed Canadian gas pipelines to be highly levered and yet attract both debt and equity at rates well below those of their U.S. counterparts. Furthermore, Canadian gas pipeline companies have operated at greater utilization rates than U.S. companies and have thereby, avoided excessive pipeline investments and expansions. Overall, the NEB's current regulatory framework appears to have avoided unnecessary risk exposure. This has resulted in Canadian gas transmission companies being able to minimize their cost of capital and cost of gas transmission service.

Recently, there has been an increase in demand for pipeline capacity from Alberta to Eastern Canada and the U.S. Midwest. Constrained pipeline capacity has created a surplus of gas supplies in Alberta and has pushed down the basin price. In turn, this has caused the price differential between Alberta-Eastern Canada and Alberta-U.S. Midwest to be greater than the full cost of transportation (that is, fixed costs plus variable costs). Therefore, there have been large economic gains (above the regulated cost of transportation) for buyers transporting gas from Alberta to Eastern Canada and the U.S. Midwest (Natural Gas Analyst, 1997b: 9). The large price differentials between markets have indicated that there is a demand for increased pipeline capacity out of Alberta.[59] To accommodate the increasing demand for pipeline capacity out of Alberta, it appears that the NEB may allow or encourage pipe on pipe competition and by-pass within the Canadian gas transmission industry. Such a change in regulatory policy and framework is a serious issue. The introduction of by-pass and pipe on pipe competition may shift existing risk from transmission customers to shareholders, and increase the overall level of risk exposure in the gas transmission industry. A substantial increase in risk exposure could negatively impact the capital structure, cost of capital, and cost of gas transmission for Canadian gas pipelines. Therefore, it is expected that the cost of capital and capital structure of Canadian gas pipelines would move in the direction of U.S. gas pipelines as illustrated in Figure 5.1.

FIGURE 5.1 COST OF CAPITAL FOR U.S. & CANADIAN GAS TRANSMISSION COMPANIES



U.S. Bond Ratings[61] A B++

Canadian Bond Ratings A++ A+ A B++

The problem that exists is that the potential risks that could impact the Canadian

[59] For example, the Canadian gas transmission industry has responded with several pipeline expansions to the U.S. Midwest. Specifically, Northern Border Pipeline Co., TCPL, and Alliance will provide an additional 2.4 bcf/d of capacity out of Alberta by the end of 2000.

[60] The cost of capital for TCPL in 1997 was 9.85%. **Source:** National Energy Board (1997: 10).

[61] Refer to Tables A4 (Appendix A) and 3.1 for evidence of the bond rating assumptions.

gas transmission industry are new. Therefore, the magnitude of the increase in risk exposure and the reaction of shareholders, bond rating agencies, and capital markets is uncertain. Because of this, it would have been difficult to use an analytical optimizing framework to measure the effects of changes in risk exposure on capital structure, cost of capital, and gas transmission costs for Canadian gas pipelines. To address this problem, the thesis employs a non-optimizing spreadsheet/simulation model that incorporates bond rating guidelines. The model demonstrated how a change in risk exposure can be expected to affect the capital structure, cost of capital, and transmission costs for a Canadian gas pipeline that uses cost of service pricing methodology. Since the vintage and transmission systems are different for each Canadian gas transmission company, the model and simulations used TCPL as a benchmark.

Various sensitivities were used in the thesis to capture the different degrees of reaction from pipeline shareholders. There were three different levels of sensitivities for an A and B++ bond rating: low sensitivity, medium sensitivity, and high sensitivity. The sensitivities were based on the current spreads between utility and corporate bond yields.

Various simulations were used to capture different increases in risk exposure that could face pipelines and their shareholders. Specifically, the simulations were based upon various capital structures and stranded costs. There were four simulation sets, I-IV. Each simulation set represented a different level that the capital structure may adjust to. The more significant the decrease in the debt-to-equity ratio, the larger the increase in risk exposure. In each simulation set (except Simulation I) five simulations were undertaken. Each simulation represented a different risk premium that may be expected to adequately compensate shareholders for recovering stranded costs. These ranged from a risk premium of zero to 11.25%.

In Simulation I the objective was to determine whether modest changes in the capital structure significantly affected the cost of capital and cost of gas transmission for Canadian natural gas pipelines. The results indicated that if Canadian gas transmission companies were allowed to determine their own capital structure within a modest range of the common equity ratio deemed by the NEB, transmission costs could change by a maximum of about 2% from what they otherwise might be.

Simulations Sets II-IV demonstrated how changes in capital structure, due to an increase in risk exposure, affected the cost of gas transmission. The results indicated that a decline in the capital structure due to an increase in risk exposure, could greatly affect transmission costs and customer rates. Table 5.1 summarizes the results from the simulations and sensitivities that were undertaken. If there are no stranded costs expected, the results indicated that that the cost of gas transmission would increase less than 10%. On the other hand, if stranded costs are expected, the cost of gas transmission can be expected to increase by at least 10%. Overall, the more significant the decline in the debt-to-equity ratio and/or the greater the risk premium required to compensate shareholders for recovering stranded costs, the greater the impact on transmission costs.

TABLE 5.1: PERCENTAGE CHANGE IN THE COST OF GAS TRANSMISSION

	Simulation Set II		Simulation Set III		Simulation Set IV	
	Low	High	Low	High	Low	High
No Stranded Costs	0.83%	4.54%	2.74%	6.39%	6.31%	9.91%
Stranded Costs	10.50%	34.97%	12.06%	35.84%	14.99%	37.51%

With regard to the other Canadian gas pipelines, the impact of a change in capital structure due to an increase in risk exposure, is largely dependent upon the percentage of capital costs relative to total costs. As shown in Table 1.1, the cost of capital as a percentage of total costs for Westcoast is similar to that of the benchmark pipeline. Therefore, the results presented here would be comparable for Westcoast. For ANG, the cost of capital as a percentage of total costs is significantly lower than that of the benchmark pipeline. Therefore, one would expect the results of the benchmark pipeline to overestimate those for ANG. On the other hand, the cost of capital as a percentage of total costs for Foothills and TQM is slightly higher than that of the benchmark pipeline. Therefore, the results for the benchmark pipeline would underestimate those for Foothills and TQM.

The most likely scenarios for the Canadian gas transmission industry in the short run and long run were also examined. The short run was an evaluation of the industry in the next five years. This time period was characterized as a transition phase where mechanisms will be developed and implemented so the industry can move towards complete pipe on pipe competition. The long run was an evaluation of the industry in the next five to ten years where the industry should have transformed from a monopoly to competition. The scenario that is of most interest is the long run.

In the long run, the most likely scenario appeared to be High Sensitivity (B++) under Simulation Set IV. Simulation Set IV is where the debt-to-common equity ratio decreased approximately to that currently used by U.S. gas pipelines. High Sensitivity (B++) is where the costs of financial capital increased 85 basis points from the current state. Therefore, based on the non-optimizing spreadsheet/simulation model, the Canadian gas transmission industry can be expected to display the following characteristics in the long run: the debt-to-common equity ratio will decrease from 60%:30% to 45:45%; the cost of capital will increase from 9.85% to 10.79%; the cost of gas transmission will increase 16.50%; and, the average toll can be expected to increase approximately $0.0395/Mcf.[62] It should be emphasized that the results presented here would for the most part be irreversible. Once by-pass and pipe on pipe competition are introduced, there is no reason to believe that there will be a reduction in risk exposure and in turn, costs. Furthermore, even if short run stranded costs are recovered, there will always be a probability that a portion of a pipeline's system will be stranded in the future. Therefore, pipeline shareholders will still have to be compensated for the risks that they can be expected to face.

5.2 CORE IMPLICATIONS

The introduction of by-pass and pipe on pipe competition within the Canadian gas transmission industry may greatly affect the cost of capital, capital structure, and transmission costs of pipeline companies. Therefore, the results suggest that the NEB

[62] Assuming that there is a risk premium of 250 basis points to adequately compensate shareholders. Refer to Appendix D for toll calculation.

may want to reconsider its current policy stance and take into account the implications on risk exposure, capital costs, and tolls in making decisions concerning by-pass and the introduction of pipe on pipe competition. The role or purpose of the NEB is to make decisions that are fair, objective, and respected. This purpose is achieved by regulating in the Canadian public interest (NEB, 1998). However, by-pass and the introduction of pipe on pipe competition are policies that may not serve the public interest. The adoption of such policies could increase the cost of gas transmission significantly from what it otherwise might be. Furthermore, at least some group(s) of customers will have to pay higher rates to pay for the increase in costs compared to those under the current cost of service pricing methodology. Therefore, the introduction of by-pass and pipe on pipe competition will result in some parties in the Canadian gas transmission industry being made worse off. Under such circumstances, these policies would not provide a Pareto improvement to the Canadian gas transmission industry.

Even in the absence of further moves to competition and light-handed regulation, it appears that regulators should relax the restrictions on capital structure. The results from Simulation I demonstrated that if a pipeline company is allowed to determine its own capital structure within a modest range of the common equity ratio deemed by the NEB, the cost of gas transmission will increase a maximum of 2%. Therefore, regulators such as the NEB, can reduce some of the regulatory burden and costs by allowing pipeline companies to determine their own capital structure within a modest range. Such a policy would benefit pipeline companies and permit regulators to focus more attention on minimizing the risk exposure faced by transmission companies. Nonetheless, if the NEB decides to allow by-pass and pipe on pipe competition into the industry, it will have to reevaluate some its policies and consider the core implications for the Canadian gas transmission industry.

Traditionally, the NEB has protected the scale and other economies of gas pipelines by discouraging inefficient by-pass and pipe on pipe competition. However, if the NEB wants to promote competition within the Canadian gas transmission industry, it will have to reconsider its policy towards entry and investment. In order to reduce the market power of existing gas transmission companies and promote competition, the NEB may have to implement transition mechanisms. Furthermore, if the industry were to truly become competitive, one would expect the NEB to allow the market to determine its entry and investment decisions. Such a policy would reduce some regulatory burden and costs, but it may also result in overbuilding and excess capacity. This could be viewed as an inefficient use of capital and could have negative implications for parks, historic sites, archaeological sites, and wetlands. Under the traditional framework, the number of right-of-ways and in turn, the environmental impacts were minimized. However, the more entrants that are allowed into the transmission industry, the greater the number of right-of-ways and in turn, the more significant the environmental impacts. Based on these observations combined with the other costs identified in this thesis, one might question from a public policy perspective, whether pipe on pipe competition can be efficiently introduced within the Canadian gas transmission industry.

The NEB can also be expected to reduce some of its regulatory burden by encouraging the market to negotiate disputes and settlements. For example, pipeline companies would negotiate the terms and conditions of service with their customers, thereby removing the need for hearings regarding rate design. Allowing the market to settle its negotiations would reduce some of the regulatory burden and costs. However, in a competitive environment there will still be costs to negotiate settlements. In fact, pipeline companies may find that it is more costly to negotiate their own terms and conditions of service with their customers. Regulators may also find it increasingly difficult to align outcomes of privately negotiated arrangements (which may only be legal because of 'regulated conduct') with broader 'public interest' objectives (Mansell, 1998: 9). Furthermore, negotiated contracts may conflict with the well-accepted principle that the same rate should be charged for the same services using identical facilities. Therefore, the NEB has to determine whether allowing the market to negotiate settlements and determine the outcome for the Canadian natural gas pipeline industry is in the Canadian public interest.

The NEB must also develop a policy to manage the existence of stranded assets. It would be unfair to change the rules on cost recovery for investments that have already been made and approved under regulation. Therefore, the NEB will have to implement a transition mechanism to address this issue. Furthermore, the NEB has to determine whether stranded costs are to be fully or partially recovered, and who will pay for these costs. Fore example, to avoid rate shock, the recovery of stranded costs can always be spread over time. With regard to the recovery of stranded costs, it was assumed in the research presented here that shareholders would be responsible. If this is the case, the NEB would then have to determine a risk premium for shareholders so they are fairly compensated for recovering stranded costs. If they are not adequately compensated, capital markets could react by further increasing the costs of financial capital.

By-pass and the introduction of pipe on pipe competition will also have an impact on the rate design of pipeline companies. If the cost of gas transmission increases by at least 10% and customers have a greater opportunity to seek more competitive rates, there is the possibility that customers with high load use and elastic demand could decontract their current service. Decontracting describes the behavior of pipeline customers that fail to renew their contracts for firm transportation service. McDonald (1996: 24) explains that:

> Decontracting occurs when the combined cost of alternative service is less than the cost of holding primary firm transportation capacity, and when shippers with access to multiple pipelines find gas delivered by another pipeline to be less expensive than gas delivered by their current transporter.

The fear in this is that if a significant number of customers with high load use decontract their service with their current gas transporter, the load factor on pipeline systems will decrease, thereby raising the possibility of a death spiral. Harvie (1997: 10-11) explains that:

> A death spiral occurs when a pipeline's throughput decreases. Tolls for the remaining shippers increase since costs remain constant and this forces other shippers off the line. Tolls will increase again since throughput has decreased. The whole thing culminates with the economic death of the last firm shipper on the system that bears the entire system costs on its own, followed shortly thereafter by the death of the pipeline itself.

Therefore, in order to stabilize the utilization rate of their systems and their profitability, pipeline companies will have to reevaluate their rate design.

Gas transmission companies could maintain their load factors by offering high load use customers service contracts which are discounted. For example, to secure throughput in the short run, pipeline companies can discount firm transportation contracts. Pipeline companies can also be expected to offer short term firm and interruptible service contracts which are discounted at market rates. Therefore, rate discounting would be a response to pipe on pipe competition. Such an expectation is supported by evidence in the U.S. gas transmission industry. For example, Figure 2.1 illustrated that as competition increased in the U.S. gas transmission industry, pipeline companies have had to use more rate discounting to secure throughput.

A problem with rate discounting is that to guarantee that fixed costs are recovered and there is not a loss in revenues, pipeline companies will have to adjust rates for other customers upward (that is, customers with inelastic demand). Some may argue that this is fair since the additional fixed costs constitute a reduction in pre-existing subsidies flowing to remaining customers and formerly borne by the by-pass customer (Lambert, 1986: 13). However, such a policy may violate the NEB's objective of "fairness and equity" which implies that tolls are to be "just and reasonable". Under such conditions, customers with inelastic demand will face higher rates for receiving their current level and quality of service. Therefore, one could argue that they would be unjustly discriminated against.

Such a policy could also have very serious implications for pipeline companies if rate design is not properly adjusted. Pipeline companies must redesign rates so that the remaining customers do not decontract their service and seek more competitive rates on another system or switch to another energy source. Therefore, it would be beneficial for pipeline companies to determine the demand elasticity for its customers.

Another potential problem is that there is no incentive for customers to secure long-term service contracts (firm transportation service) when pipeline systems have excess capacity. Customers can be expected to switch their transportation services from firm service to short term firm service or interruptible service. Pipeline customers would still be transporting their current levels of gas, but at much lower rates. Such a scenario is a possibility as a large number of contracts are expiring in the next five years. For example, Foothills indicated that 82% of its transportation service contracts expire between 2001 and 2004 (NEB, 1995: 12). This implies that gas transmission companies may have to redesign rates so a greater percentage of fixed costs are recovered in short term firm and interruptible service contracts. For example, Figure 2.2 illustrated that the percentage of fixed costs allocated to interruptible transmission in the U.S. gas industry has been increasing annually since pipe on pipe competition was introduced.

Another serious implication for the Canadian gas transmission industry is that the financial health and investment decisions of pipeline companies may be adversely affected. The introduction of by-pass and pipe on pipe competition may affect the ability of Canadian gas pipelines to attract capital at reasonable rates. For example, there is the possibility that they may have to raise additional financial capital in other markets, such as the U.S. TCPL has indicated that many Canadian institutional investors simply cannot buy debt with a rating below that A category. Of those that can buy B++ rated debt, their capacity to do so is significantly less than that which they have to purchase in the A category or above (NEB, 1995: 9). Table A7 (Appendix A) indicates that the ten-year government bond yield is generally higher in the U.S. than in Canada. Therefore, if Canadian gas pipeline companies finance their debt in the U.S. market, the cost of capital and cost of gas transmission results from the simulations are probably underestimated.[63] This implies that the impact on tolls and the implications for the industry could be much greater than anticipated. Furthermore, even if the financial health of Canadian pipeline companies is not initially affected by pipe on pipe competition, the loss of major customers has the potential of adversely affecting a pipeline's bond rating and ability to attract capital.

The investment decisions of Canadian gas transmission companies could also be significantly affected. The hurdle rate is defined as the minimum rate of return on a project. If the expected rate of return is below the hurdle rate, the project is not accepted (Birk, 1989: 395). Therefore, since the hurdle rate for new investments will have increased due to an increase in risk exposure, it may be that the probability of accepting

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[63] The results are possibly underestimated since they are based on Canadian pipeline companies financing their debt in Canada.

new investments will decrease. A decrease in investment could result in less taxes and royalties, and fewer employment opportunities, as companies find other markets for their business.

Shippers must realize that the move to competition in the Canadian pipeline industry will lead to greater costs and uncertain benefits. Often, it is suggested that competition would produce benefits such as: lower risk and rates for shippers; increase the quality and reliability of service; and, present more options for customers. However, the research presented here suggests that by-pass and the introduction of pipe on pipe competition may increase the cost of gas transmission at least 10% from what it otherwise might be. This is equivalent to an increase in the average toll by approximately \$0.0245/Mcf.[64] Such an increase in costs must imply that not all rates for customers will be lower and at least some producers will face lower netbacks. One may expect that in a more competitive environment where there is excess pipeline capacity, shippers would try to force tolls down to as low as variable costs. This is due to shippers acknowledging that pipelines only need to recover these variable costs to stay operational in the short run. However, transmission companies will have to recover their fixed and variable costs in the long run. Therefore, from a long run perspective, one would expect that for at least some customers, rates will be higher from what they otherwise might be. In turn, this implies that some producers' netbacks may be significantly reduced in a more competitive pipeline environment. Such an impact could have a significant affect on producers' operations and the development of natural gas industries in remote regions, such as northern Alberta, which are a long distance from markets.

An increase in the cost of gas transmission and tolls by at least 10% could also constitute rate shock. Rate shock refers to situations where annual rates of increase in tolls are in 'double digits' (Mansell and Church, 1995: 56). Furthermore, transmission companies and customers might expect to face unpredictable rates as throughput on pipeline systems will become more variable. Rate predictability is particularly important to industrial customers whose own investment and consumption designs are dependent on

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[64] Refer to Appendix D for toll calculation.

the cost of utility services (Sherwin and McShane, 1992: 10).

Under current cost of service pricing methodology in the Canadian gas transmission industry, there is no incentive for gas pipelines to reduce costs by decreasing quality of service. Therefore, it is uncertain whether a competitive environment would improve the quality of service currently provided. It is also uncertain whether reliability of service will be improved when customers could be contracting a greater percentage of their gas transmission service with short term firm and interruptible service contracts. Therefore, to argue that in a more competitive Canadian gas transmission industry, all customers will have better quality and reliability of service, and lower rates, does not appear to hold.

Overall, the results and implications suggest that prior to adoption of a policy of approving projects involving by-pass and pipe on pipe competition, it would be important to establish whether the benefits outweigh these higher costs. Any shift in the current regulatory or operating framework must be supported by a high probability that the alternative regulatory mode will produce net benefits.

5.3 RELEVANCE OF THE RESEARCH AND RESULTS

The research presented here is timely and highly relevant to the Canadian gas transmission industry. At the moment, the NEB appears to be on a path of allowing or encouraging pipe on pipe competition and by-pass within the industry to accommodate the increase in demand for pipeline capacity out of Alberta. Furthermore, a brief survey was conducted previous to the writing of this thesis with several of the financial departments of Canadian gas pipelines. The objective of the survey was to determine how Canadian gas pipelines would react if they were allowed to determine their own capital structure. Further, how would by-pass and pipe on pipe competition affect their risk exposure and capital structure? The basic consensus was that if Canadian pipelines could set their own debt-to-equity ratio, they would choose to hold more common equity. However, most of the pipelines also responded that they have not given much attention to this issue since the NEB's multi-cost pipeline hearing, RH-2-94. At this hearing, the NEB derived a formula for calculating cost rates and deemed a common equity ratio for its pipelines. With regard to the impact of by-pass and pipe on pipe competition, it was viewed that such policies would make the industry more efficient and only improve the operations of Canadian gas transmission companies. The general consensus was that there might be a slight increase in risk exposure and this in turn, may cause a decrease in the debt-to-equity ratio. However, the cost of capital and cost of gas transmission should not be negatively affected.

Based on these observations, it is uncertain whether the Canadian gas transmission industry fully comprehends how risk exposure can affect the capital structure, cost of capital, and cost of gas transmission for Canadian gas pipelines. There have been no known studies which examined this issue. Furthermore, the NEB has not even conducted an analysis whether competition would provide any net benefits to the Canadian gas transmission industry. Therefore, the NEB and the industry cannot simply undertake competition because in theory it will produce a more efficient environment. Competition has been fairly successful in telecommunications and the electric industry, but this due to technological changes that have reduced the significance of economies of scale. In the Canadian gas transmission industry, technological changes have favored larger diameter pipelines and larger compressors and have increased rather the decreased the significance of economies of scale (Mansell and Church, 1995: 13).

Based on the non-optimizing spreadsheet/simulation model, the results indicate that the introduction of by-pass and pipe on pipe competition within the Canadian gas transmission industry is a serious issue. Under such circumstances, the cost of gas transmission may increase at least 10%. This is equivalent to an increase in the average toll by approximately $0.0245/Mcf.[65] Furthermore, there would be serious implications for the industry that could affect the profitability and development of the Canadian gas transmission industry in Canada.

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[65] Refer to Appendix D for toll calculation.

5.4 SHORTCOMINGS OF THE RESEARCH

The most significant shortcoming with the research is that the predictive power of the model is uncertain. The problem is that it is uncertain how pipeline companies, shareholders, and bond rating agencies will react to competition, as it is a new phenomena to the industry. But this is exactly why the non-optimizing spreadsheet/simulation model was employed. If anything, the simulations and sensitivities would understate the actual results. For example, it has been indicated that if Canadian pipelines' bond ratings were downgraded to B++, they would not be able to sell their debt instruments to many Canadian institutions. However, the simulations and sensitivities assumed that Canadian gas pipeline companies would be able to finance their debt in Canada. Table A7 (Appendix A) indicates that the ten-year government bond yield is generally higher in the U.S. than in Canada. Therefore, if Canadian gas pipelines finance their debt in the U.S. market, the cost of capital and cost of gas transmission are probably understated.

It would also have been beneficial to have empirically tested the effects of varying debt-equity ratios on the cost of capital for gas pipelines in North America along with the spreadsheet/simulation. However, there were several major stumbling blocks to undertaking this procedure:

1. Data for U.S. pipelines is sketchy and limited, since the vast majority of rate of return and capital structure components of rate cases at the FERC are settled among the parties. Even the settlements do not necessarily specify the return on equity and capital structure, but rather the total dollars of return (equity and debt) and taxes.
2. It is difficult determining the market value of common equity for pipelines as a number of transmission companies are subsidiaries. For example, in Moody's Public Utility Manual the market value of common equity for such companies is generally not listed. To deal with this problem, one could use a proxy for the cost of equity. However, out of a sample of approximately 50 transmission companies in the U.S. and Canada, more than half of the

companies do not have market values for their common equity listed. Therefore, the introduction of a proxy for these companies could cause model misspecification which would produce unreliable results.

3. Furthermore, a large number of pipelines that operate in the U.S. and Canada are not solely transmission companies. For example, Williams Natural Gas Co. has operations in the transmission of natural gas, but it also has a large portion of its business in other activities such as energy processing and marketing. Therefore, even if the market value of common equity was determined for a significant number of companies, it would be difficult to determine what portion of the market value is attributable to its transmission operations.

For simplicity, it was also assumed that an increase in risk exposure would only affect the funded debt and common equity instruments in the capital structure portfolio. However, such an outcome is highly unlikely. Nonetheless, I believe that altering the other capital instruments would not have significantly affected the results of the research presented here.

It was also assumed in the research that any stranded costs that resulted from by-pass or pipe on pipe competition would be recovered from pipeline shareholders. Whether this will be true in the Canadian gas transmission industry is uncertain. Nonetheless, even if transmission customers were fully responsible for stranded costs, or transmission customers and pipeline shareholders jointly had to pay these costs, transmission costs would be greatly affected. Therefore, determining who should recover stranded costs should not significantly affect the impact of risk exposure on the cost of gas transmission.

One last shortcoming is that it was assumed that the load factor for TCPL would remain at 95% for all toll calculations. However, it has been argued here that by-pass and the introduction of pipe on pipe competition may decrease the utilization rates of Canadian gas transmission systems. Therefore, such an assumption is unrealistic and produces results which are understated. For example, a 10% increase in the cost of gas transmission and a 95% load factor results in an increase in the average toll by approximately \$0.0245/Mcf. On the other hand, a 10% increase in transmission costs and a 90% load factor would result in an increase in the average toll by approximately \$0.0395/Mcf.[66]

5.5 AREAS OF FURTHER RESEARCH

Several issues were highlighted throughout the research, but were left unresolved as they were beyond the scope of this study. This section presents some possible areas of further research. These include:

1. Estimating the elasticity of demand for Canadian gas transmission customers. By-pass and pipe on pipe competition will probably force pipeline companies to adjust their rate designs. To effectively redistribute the increase in costs, pipeline companies must recognize the demand elasticities of its customers. This will allow pipeline companies to increase rates for customers with inelastic demand, offer discounted rates for customers with elastic demand, and not significantly impact the utilization rate of their system.
2. Assuming that an increase in risk exposure would only affect the funded debt and common equity instruments in the capital structure portfolio is unrealistic. If there was a significant increase in risk exposure, pipeline companies may want to alter their capital structure portfolio to minimize the cost of transmission service. For example, it may be more cost efficient if pipeline companies reduce the amount of preferred share capital and debentures in their capital structure. Therefore, it would be interesting to examine how a change in risk exposure affects all of the capital instruments in the capital structure portfolio.
3. It may also be beneficial if further research was conducted in the telecommunication and electric industries. Specifically, lessons may be learned from their transition to competition and applied to the Canadian gas transmission industry. Furthermore, enough time may have elapsed in these industries to study whether competition is more efficient than monopoly.

[66] Refer to Appendix D for toll calculations.

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Appendix A - Tables

TABLE A1: CAPITAL STRUCTURE OF CANADIAN NATURAL GAS PIPELINES (1996)

	Debt (%)	Preferred (%)	Common Equity (%)
ANG	70.0	0.0	30.0
Foothills	70.0	0.0	30.0
TQM	70.0	0.0	30.0
TCPL	62.2	7.8	30.0
Westcoast	63.5	1.5	35.0
Average	67.14	1.86	31.0

Source: National Energy Board (1997a: 39).

TABLE A2: CAPITAL STRUCTURE OF U.S. NATURAL GAS PIPELINES (1996)

	Debt (%)	Preferred (%)	Common Equity (%)
Algonquin	24.0	0.0	76.0
ANR Pipeline Co.	41.0	0.0	59.0
Bear Creek Storage Co.	39.0	0.0	39.0
Black Marlin Pipeline Co.	0.0	0.0	100.0
Chandleur	1.0	0.0	99.0
CNG Transmission Corp.	34.0	0.0	66.0
Colorado Interstate Gas Co.	35.0	0.0	65.0
Columbia Gas Transmission Corp.	42.0	0.0	58.0
Columbia Gulf Transmission Corp.	37.0	0.0	63.0
East Tennessee Natural Gas Co.	8.0	0.0	92.0
El Paso Natural Gas Co.	36.0	0.0	64.0
Equitrans, L.P.	30.0	0.0	70.0
Florida Gas Transmission Co.	54.0	0.0	36.0
Great Lakes Gas Transmission Ltd. Part.	47.0	0.0	53.0
High Island Offshore System	0.0	0.0	100.0
Iroquois Gas Transmission System	67.0	0.0	33.0
KN Interstate Gas Transmission Co.	62.0	0.0	38.0
Kern River Gas Transmission Co.	70.0	0.0	30.0
Koch Gateway Pipeline Co.	0.0	0.0	100.0
Michigan Gas Storage Co.	41.0	0.0	59.0
Midwestern Gas Transmission Co.	0.0	0.0	100.0
Mississippi River Transmission Corp.	51.0	0.0	49.0
Mobile Bay Pipeline Co.	97.0	0.0	3.0
Mojave Pipeline Co.	60.0	0.0	40.0
National Fuel Gas Supply Corp.	41.0	0.0	59.0
Natural Gas Pipeline Co. of America	0.0	0.0	100.0
NorAm Gas Transmission Co.	61.0	0.0	39.0
Northern Border Pipeline Co.	62.0	0.0	38.0
Northern Natural Gas Co.	37.0	0.0	63.0
Northwest Alaskan Pipeline Co.	0.0	0.0	100.0
Northwest Pipeline Corp.	45.0	0.0	55.0
Overthrust Pipeline Co.	7.0	0.0	93.0
Pacific Gas Transmission Co.	53.0	0.0	47.0
Panhandle Eastern Pipe Line Co.	38.0	0.0	62.0
Questar Pipeline Co.	42.0	0.0	58.0
Sabine Pipe Line Co.	0.0	0.0	100.0
Sea Robin Pipeline Co.	0.0	0.0	100.0

TABLE A2 CONTINUED			
Southern Natural Gas Co.	35.0	0.0	65.0
Stingray Pipeline Co.	48.0	0.0	52.0
Tennessee Gas Pipeline Co.	35.0	0.0	65.0
Texas Eastern Transmission Corp.	50.0	0.0	50.0
Texas Gas Transmission Corp.	36.0	0.0	64.0
Trailblazer Pipeline Co.	41.0	0.0	59.0
TransColorado Gas Transmission	0.0	0.0	100.0
Transcontinental Gas Pipeline Corp.	41.0	0.0	59.0
Transwestern Pipeline Co.	23.0	0.0	77.0
Trunkline Gas Co.	40.0	0.0	60.0
U-T Offshore System	0.0	0.0	100.0
Viking Gas Transmission Co.	63.0	0.0	37.0
Williams Natural Gas Co.	39.0	0.0	61.0
Williston Basin Interstate Pipeline	30.0	7.0	63.0
Wyoming Interstate Co., Ltd.	18.0	0.0	82.0
Average	34.0	0.0	66.0

Source: Federal Energy Regulatory Commission (1996b).

TABLE A3: BOND RATINGS OF CANADIAN GAS PIPELINES YEAR-END 1995

	Long Term Debt Rating	Debt-to-Equity Ratio
ANG	A(Low)	57:43%
Foothills	A(Low)	69:31%
NGTL	A(Low)	67:33%
TQM	A(Low)	70:30%
TCPL	A	63:37%
Westcoast	A(Low)	75:25%

Source: Canadian Bond Rating Service (1996).

TABLE A4: BOND RATINGS OF MAJOR U.S. GAS PIPELINE COMPANIES

	Senior Debt Rating	Debt Ratio Average (1993-1989)
Consolidated Natural Gas Co.	A1	31.16
El Paso Natural Gas Co.	A3	39.91
KN Interstate Gas Transmission Co.	A3	43.61
Sonat Inc.	Baa1	44.86
Enron Corp.	Baa2	53.01
Coastal Corp.	Baa3	58.48
Williams Natural Gas Co.	Baa3	51.11
Panhandle Eastern Pipe Line Co.	Ba1	59.23
Arkla Inc.	Ba2	53.61
Transcontinental Gas Pipeline Corp.	Ba3	57.21
Columbia Gas Transmission Corp.	Caa	60.50

Source: Moody's Investors Service (1994: 18).

TABLE A5: COMPARISON OF BOND RATINGS BETWEEN AGENCIES

CBRS	Standard & Poor's	Moody's
A++	AAA	Aaa
A+	AA	Aa
A	A	A
B++	BBB	Baa
B+	BB	Ba
B	B	B
C	CCC	Caa
D	CC	Ca
	C	C
	D	

Source: Cantwell (1994: 47).

TABLE A6: BOND RATING DESCRIPTIONS

	CBRS		Standard & Poor's
A++	Bonds possessing the highest degree of protection of principal and interest. Strong evidence that the quality of the assets and earnings of the company will continue.	AAA	The highest rating assigned by S&P with extremely strong ability to pay principal and interest.
A+	Bonds considered to be superior in quality however the margin of assets or earnings protection may not be as stable as those rated A++.	AA	Bonds with a very strong capacity to pay principal and interest.
A	Bonds considered to be of good quality with favorable long-term investment characteristics. These companies may be more susceptible to changes in economic conditions.	A	Bonds with a strong capacity to pay principal and interest but are somewhat more susceptible to economic changes.
B++	Bonds considered to be of medium or average quality. These bonds are considered to be investment grade. These companies may be more susceptible to changes in economic conditions.	BBB	Bonds with adequate capacity to pay principal and interest but more likely to be affected by economic changes.
B+	Bonds considered to be of lower medium quality. These bonds are characterized by a deterioration in interest and principal protection.	BB	Bonds with speculative characteristics. Economic conditions could lead to inability to pay principal and interest.
B	Bonds considered to be of poor quality. There is doubt as to whether interest and principal protection will be adequately maintained.	B	Bonds with a greater vulnerability to default but which currently have the ability to pay principal and interest.
C	Bonds which are clearly speculative where there is little assurance of principal and interest coverage.	CCC	Bonds with an identifiable vulnerability to default which is not likely to be able to pay principal and interest in the event of unfavorable economic changes.
D	Bonds in default.	CC	rating applied to debt subordinated to senior debt that is assigned a "CCC" rating.

	TABLE A6 CONTINUED		
		C	Rating applied to debt subordinated to senior debt that is assigned a "CCC-" rating.
		D	Bonds in default.

Source: Cantwell (1994: 43-44).

TABLE A7: HISTORIC TEN-YEAR GOVERNMENT BOND YIELD AVERAGES: U.S AND CANADA

	U.S.	Canada
May 1998	5.58%	5.34%
April 1998	5.68%	5.40%
March 1998	5.68%	5.39%
February 1998	5.70%	5.50%
January 1998	5.52%	5.40%
December 1997	5.75%	5.65%
November 1997	5.88%	5.65%
October 1997	5.83%	5.53%
September 1997	6.16%	5.77%
August 1997	6.39%	6.00%
July 1997	6.00%	5.80%
June 1997	6.52%	6.35%
May 1997	6.70%	6.51%
April 1997	6.72%	6.69%
March 1997	6.56%	6.80%
February 1997	6.56%	6.46%
January 1997	6.59%	6.63%

Source: Canadian Bond Rating Service (1998a).

TABLE A8: HISTORIC TEN-YEAR CANADIAN BOND YIELD AVERAGES: UTILITIES AND CORPORATIONS

	Utilities				Corporate			
	A+	A	B++		A++	A+	A	B++
May 1998	5.70%	5.86%	6.02%		5.73%	5.74%	5.92%	6.74%
April 1998	5.77%	5.94%	6.11%		5.81%	5.82%	6.00%	6.80%
March 1998	5.76%	5.94%	6.09%		5.82%	5.83%	5.99%	6.89%
February 1998	5.89%	6.08%	6.22%		5.94%	5.95%	6.13%	7.05%
January 1998	5.80%	5.97%	6.10%		5.85%	5.86%	6.01%	6.90%
December 1997	6.01%	6.16%	6.33%		6.07%	6.08%	6.22%	6.95%
November 1997	6.02%	6.05%	6.31%		6.06%	6.07%	6.21%	6.95%
October 1997	5.89%	5.99%	6.16%		5.92%	5.93%	6.05%	6.73%
September 1997	6.09%	6.17%	6.37%		6.11%	6.12%	6.25%	6.82%
August 1997	6.30%	6.40%	6.57%		6.34%	6.35%	6.48%	7.05%
July 1997	6.11%	6.20%	6.37%		6.14%	6.15%	6.30%	6.90%
June 1997	6.67%	6.77%	6.94%		6.70%	6.71%	6.86%	7.55%
May 1997	6.85%	6.95%	7.11%		6.87%	6.89%	7.04%	7.71%
April 1997	7.03%	7.14%	7.29%		7.04%	7.06%	7.22%	7.84%
March 1997	7.15%	7.26%	7.40%		7.16%	7.18%	7.34%	7.95%
February 1997	6.78%	6.90%	7.02%		6.80%	6.82%	6.96%	7.63%
January 1997	6.97%	7.10%	7.22%		6.99%	7.02%	7.16%	7.93%
December 1996	6.76%	6.87%	7.01%		6.78%	6.81%	6.94%	7.81%
November 1996	6.35%	6.48%	6.65%		6.38%	6.42%	6.53%	7.51%
October 1996	6.77%	6.89%	7.07%		6.78%	6.81%	6.94%	7.92%
September 1996	7.46%	7.57%	7.69%		7.47%	7.50%	7.65%	8.57%
August 1996	7.75%	7.83%	7.97%		7.77%	7.80%	7.95%	8.85%
July 1996	7.96%	8.07%	8.16%		8.00%	8.03%	8.17%	9.10%
June 1996	7.97%	8.08%	8.17%		8.00%	8.05%	8.16%	9.10%
May 1996	8.09%	8.22%	8.31%		8.12%	8.16%	8.31%	9.18%
April 1996	8.18%	8.33%	8.50%		8.20%	8.25%	8.39%	9.22%
Average 1998-1996	6.70%	6.82%	6.97%		6.73%	6.75%	6.89%	7.68%

Source: Canadian Bond Rating Service (1998a).

Appendix B - Calculations

B.1 CALCULATIONS OF THE MODEL

MODEL PART A: IMPACT OF LEVERAGE ON THE COST OF CAPITAL

Funded Debt		Bond Rating	Unfunded Debt		Junior Sub. Deb.		Preferred Share		Common Equity		Cost of Capital
Cost	%		Cost	%	Cost	%	Cost	%	Cost	%	
9.97	49.7	A+	6.79	5.75	8.45	2.85	7.16	6.70	10.55	35.0	9.76%
10.09	54.7	A	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.24	59.7	B++	7.06	5.75	8.72	2.85	7.43	6.70	10.82	25.0	9.97%

Cost of Capital = 9.85% = current state
= (cost of funded debt x percentage of funded debt) + (cost of unfunded debt x percentage of unfunded debt) + (cost of junior subordinated debentures x percentage of junior subordinated debentures) + (cost of preferred share equity x percentage of preferred share equity) + (cost of common equity x percentage of common equity)

$$= (10.09 \times 54.7) + (6.91 \times 5.75) + (8.57 \times 2.85) + (7.28 \times 6.70) + (10.67 \times 30.0) \quad \textbf{(EQ. B1.1)}$$

Cost of Capital = 9.76%

$$= ((10.09 - 0.12) \times 49.7) + ((6.91 - 0.12) \times 5.75) + ((8.57 - 0.12) \times 2.85) + ((7.28 - 0.12) \times 6.70) + ((10.67 - 0.12) \times 35.0) \quad \textbf{(EQ. B1.2)}$$

Cost of Capital = 9.97%

$$= ((10.09 + 0.13) \times 59.7) + ((6.91 + 0.13) \times 5.75) + ((8.57 + 0.13) \times 2.85) + ((7.28 + 0.13) \times 6.70) + ((10.67 + 0.13) \times 25.0) \quad \textbf{(EQ. B1.3)}$$

MODEL PART B: TCPL'S TRANSPORTATION REVENUE REQUIREMENT FOR THE 1997 TEST YEAR AND THE COST OF TRANSMISSION

Incentive Cost Envelope	$689,839,000
Flow-Through Cost Envelope	
Income Taxes	***102,106,843***
Depreciation	252,230,000
Return on Rate Base	***731,633,101***
Foreign Exchange Cost	2,643,000
Electric Fuel Costs	12,680,000
Insurance Deductible Costs	3,701,000
Stress Corrosion Cracking & Corrosion Control	64,072,000
Sub Total Flow-Through Envelope	1,169,065,945
Regulatory Amortizations	(67,645,000)
Pressure Charges	4,854,000
Gross Revenue Requirement	1,796,113,945
Non-Discretionary Miscellaneous Revenue	(54,115,000)
Discretionary Miscellaneous Revenue	(12,300,000)
Interim Revenue Adjustment	(25,335,000)
Net Revenue Requirement	**$1,704,363,945**
Canadian Mainline Length (km)	14,274
Cost of Gas Transmission or Average Cost per km	**$119,403.39**

Source: National Energy Board (1997b: 4).

Incentive Cost Envelope	= transmission by others costs + operating, maintenance, and administration expenses + gas related expense + municipal and other taxes + NEB cost recovery expense
Flow-Through Cost Envelope	= return on rate base + income taxes + depreciation + foreign exchange costs + insurance deductible costs + stress corrosion cracking & corrosion control costs + electric fuel costs - additional units
Return on Rate Base	= approved rate base x approved cost of capital
Gross Revenue Requirement	= Incentive Cost Envelope + Flow-Through Cost Envelope - Regulatory Amortizations + Pressure Charges
Net Revenue Requirement	= Gross Revenue Requirement - Non-Discretionary Miscellaneous Revenue - Discretionary Miscellaneous Revenue - Interim Revenue Adjustment
Cost of Gas Transmission	= Net Revenue Requirement ÷ Canadian Mainline Length

B1: TCPL'S RATE BASE FOR THE 1997 TEST YEAR

Utility Investment	
Gross Plant	9,784,091,000
Accumulated Depreciation	(2,479,335,000)
Net Plant	7,304,756,000
Contributions in Aid of Construction	(2,410,000)
Total Plant	7,302,346,000
Working Capital	
Cash	22,243,000
GST Receivable, Net	2,320,000
Materials & Supplies	43,866,000
Transmission Linepack	39,905,000
Prepayments & Deposits	1,428,000
Total Working Capital	109,762,000
Deferred Costs	
Miscellaneous Deferred Items	37,797,000
Operating & Debt Service Deferrals	(33,211,000)
Surplus Pension	10,450,000
Total Deferred Costs	15,036,000
Total Rate Base	**$7,427,144,000**

Source: National Energy Board (1997b: 8).

Utility Investment	= gross plant + accumulated depreciation + contributions in aid of construction
Net Plant	= gross plant - accumulated depreciation
Total Plant	= net plant - contributions in aid of construction
Total Working Capital	= cash + GST receivable, net + materials & supplies + transmission linepack + prepayments & deposits
Total Deferred Costs	= deferred costs + surplus pension - operating & debt service deferrals
Total Rate Base	= total plant + total working capital - total rate base

B2: TCPL'S SCHEDULE OF FLOW-THROUGH INCOME TAXES FOR THE 1997 TEST YEAR

Equity Component	***274,061,614***
Depreciation	252,230,000
Large Corporation Tax	18,347,000
Preferred Share Dividend Tax	215,000
Non-Allowed Amortization of Debt Discount & Expense and Foreign Exchange Costs	5,708,000
Non-Allowed Expenses	(1,057,000)
Capital Cost Allowance	(413,533,000)
Benefits Capitalized	(3,281,000)
Eligible Capital Expenses	(70,000)
Interest AFUDC[67]	(14,177,000)
North Bay Litigation Costs	(4,768,000)
Issue Costs	(6,287,000)
Taxable Income	
Taxes at 0.43756 ÷ (1-0.43756) x Taxable Income	83,544,843
Recovery of Large Corporation Tax	18,347,000
Income Tax on Preferred Share Dividends	215,000
Utility Income Tax Requirement	**$102,106,843**

Source: National Energy Board (1997b: 29).

Equity Component	= $274,062,000 = allowed rate base x allowed weighted average costs of preferred and common equity = $7,427,144,000 x (0.49 + 3.20) **(EQ. B1.4)**
Taxable Income	= equity component + depreciation + large corporation tax + preferred share dividend tax + non-allowed amortization of debt discount & expense and foreign exchange costs - non-allowed expenses - capital cost allowance - benefits capitalized - eligible capital expenses interest AFUDC - North Bay litigation costs - issue costs
Utility Income Tax Requirement	= taxable income x taxes at 0.43756 ÷ (1-0.43756) + recovery of large corporation tax + income tax on preferred share dividend

[67] AFUDC is allowance for funds used during construction.

B3: TCPL'S DEEMED CAPITAL STRUCTURE AND RATES OF RETURN FOR THE 1997 TEST YEAR

	Amount	Capital Structure	Cost Rate	Cost Component
Funded Debt	4,182,574,000	54.70%	10.09%	5.52%
Unfunded Debt	439,136,000	5.75%	6.91%	0.40%
Total Debt Capital	4,621,710,000	60.45%		
Junior Subordinated Debentures	218,082,000	2.85%	8.57%	0.24%
Preferred Share Capital	512,649,000	6.70%	7.28%	0.49%
Common Equity	2,293,903,000	30.00%	10.67%	3.20%
Total Capitalization	7,646,344,000[68]	100.00%		
Rate of Return				**9.85%**

Source: National Energy Board (1997b: 10).

Cost Component = percentage of the capital structure multiplied by the cost rate

Cost Component for funded debt = 5.52%
= 54.70% x 10.09% **(EQ. B1.5)**

Cost Component for unfunded debt = 0.40%
= 5.75% x 6.91% **(EQ. B1.6)**

Cost Component for Junior Subordinated Debentures = 0.24%
= 2.85% x 8.57% **(EQ. B1.7)**

Cost Component for Preferred Shares = 0.49%
= 6.70% x 7.28% **(EQ. B1.8)**

Cost Component for Common Equity = 3.20%
= 30.0% x 10.67% **(EQ. B1.9)**

Rate of Return on Rate Base = 9.85%
= sum of the financial capital cost components
= 5.52 + 0.40 + 0.24 + 0.49 + 3.20 **(EQ. B1.10)**

[68] Rate Base $7,427,144 + GPUC $219,200 = Total Capitalization $7,646,344.
GPUC is gross plant under construction.

B.2 SENSITIVITY CALCULATIONS

LOW SENSIVITY (A): is where the cost of unfunded debt does not change from the current state. Therefore, it is assumed that the cost of unfunded debt remains at 6.91%. The overall cost of capital will be as follows for the various capital structures:

Funded Debt		**Unfunded Debt**		**Junior Sub. Deb.**		**Preferred Share**		**Common Equity**		**Cost of Capital**
Cost	**%**	**Cost**	**%**	**Cost**	**%**	**Cost**	**%**	**Cost**	**%**	
10.09	54.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.09	49.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	35.0	9.88%
10.09	39.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	45.0	9.94%
10.09	29.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	55.0	9.99%

Cost of Capital = 9.85% = current state

= (cost of funded debt x percentage of funded debt) + (cost of unfunded debt x percentage of unfunded debt) + (cost of junior subordinated debentures x percentage of junior subordinated debentures) + (cost of preferred share equity x percentage of preferred share equity) + (cost of common equity x percentage of common equity)

$$= (10.09 \times 54.7) + (6.91 \times 5.75) + (8.57 \times 2.85) + (7.28 \times 6.70) + (10.67 \times 30.0) \quad \textbf{(EQ. B2.1)}$$

Cost of Capital = 9.88%

$$= (10.09 \times 49.7) + (6.91 \times 5.75) + (8.57 \times 2.85) + (7.28 \times 6.70) + (10.67 \times 35.0) \quad \textbf{(EQ. B2.2)}$$

Cost of Capital = 9.94%

$$= (10.09 \times 39.7) + (6.91 \times 5.75) + (8.57 \times 2.85) + (7.28 \times 6.70) + (10.67 \times 45.0) \quad \textbf{(EQ. B2.3)}$$

Cost of Capital = 9.99%

$$= (10.09 \times 29.7) + (6.91 \times 5.75) + (8.57 \times 2.85) + (7.28 \times 6.70) + (10.67 \times 55.0) \quad \textbf{(EQ. B2.4)}$$

MEDIUM SENSITIVITY (A): is where the cost of unfunded debt increases 5 basis points. This is halfway between the current A utility and A corporate rated bond yield spread. Under Medium Sensitivity (A), the cost of unfunded debt increases from 6.91% to 6.96%. The overall cost of capital will be as follows for the various capital structures:

Funded Debt		**Unfunded Debt**		**Junior Sub. Deb.**		**Preferred Share**		**Common Equity**		**Cost of Capital**
Cost	**%**	**Cost**	**%**	**Cost**	**%**	**Cost**	**%**	**Cost**	**%**	
10.09	54.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.14	49.7	6.96	5.75	8.62	2.85	7.33	6.70	10.72	35.0	9.93%
10.14	39.7	6.96	5.75	8.62	2.85	7.33	6.70	10.72	45.0	9.99%
10.14	29.7	6.96	5.75	8.62	2.85	7.33	6.70	10.72	55.0	10.04%

Cost of Capital = 9.85% = current state

= (cost of funded debt x percentage of funded debt) + (cost of unfunded debt x percentage of unfunded debt) + (cost of junior subordinated debentures x percentage of junior subordinated debentures) + (cost of preferred share equity x percentage of preferred share equity) + (cost of common equity x percentage of common equity)

= (10.09 x 54.7) + (6.91 x 5.75) + (8.57 x 2.85) + (7.28 x 6.70) + (10.67 x 30.0) **(EQ. B2.5)**

Cost of Capital = 9.93%

= ((10.09 + 0.05) x 49.7) + ((6.91 + 0.05) x 5.75) + ((8.57 + 0.05) x 2.85) + ((7.28 + 0.05) x 6.70) + ((10.67 + 0.05) x 35.0) **(EQ. B2.6)**

Cost of Capital = 9.99%

= ((10.09 + 0.05) x 39.7) + ((6.91 + 0.05) x 5.75) + ((8.57 + 0.05) x 2.85) + ((7.28 + 0.05) x 6.70) + ((10.67 + 0.05) x 45.0) **(EQ. B2.7)**

Cost of Capital = 10.04%

= ((10.09 + 0.05) x 29.7) + ((6.91 + 0.05) x 5.75) + ((8.57 + 0.05) x 2.85) + ((7.28 + 0.05) x 6.70) + ((10.67 + 0.05) x 55.0) **(EQ. B2.8)**

HIGH SENSITIVITY (A): is where the cost of unfunded debt increases 10 basis points. This is the current spread between A utility and A corporate rated bond yields. Under High Sensitivity (A), the cost of unfunded debt increases from 6.91% to 7.41%. The overall cost of capital will be as follows for the various capital structures:

Funded Debt		**Unfunded Debt**		**Junior Sub. Deb.**		**Preferred Share**		**Common Equity**		**Cost of Capital**
Cost	**%**	**Cost**	**%**	**Cost**	**%**	**Cost**	**%**	**Cost**	**%**	
10.09	54.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.19	49.7	7.01	5.75	8.67	2.85	7.38	6.70	10.77	35.0	9.98%
10.19	39.7	7.01	5.75	8.67	2.85	7.38	6.70	10.77	45.0	10.04%
10.19	29.7	7.01	5.75	8.67	2.85	7.38	6.70	10.77	55.0	10.09%

Cost of Capital = 9.85% = current state

= (cost of funded debt x percentage of funded debt) + (cost of unfunded debt x percentage of unfunded debt) + (cost of junior subordinated debentures x percentage of junior subordinated debentures) + (cost of preferred share equity x percentage of preferred share equity) + (cost of common equity x percentage of common equity)

$$= (10.09 \times 54.7) + (6.91 \times 5.75) + (8.57 \times 2.85) + (7.28 \times 6.70) + (10.67 \times 30.0) \qquad \textbf{(EQ. B2.9)}$$

Cost of Capital = 9.98%

$$= ((10.09 + 0.10) \times 49.7) + ((6.91 + 0.10) \times 5.75) + ((8.57 + 0.10) \times 2.85) + ((7.28 + 0.10) \times 6.70) + ((10.67 + 0.10) \times 35.0) \qquad \textbf{(EQ. B2.10)}$$

Cost of Capital = 10.04%

$$= ((10.09 + 0.10) \times 39.7) + ((6.91 + 0.10) \times 5.75) + ((8.57 + 0.10) \times 2.85) + ((7.28 + 0.10) \times 6.70) + ((10.67 + 0.10) \times 45.0) \qquad \textbf{(EQ. B2.11)}$$

Cost of Capital = 10.09%

$$= ((10.09 + 0.10) \times 29.7) + ((6.91 + 0.10) \times 5.75) + ((8.57 + 0.10) \times 2.85) + ((7.28 + 0.10) \times 6.70) + ((10.67 + 0.10) \times 55.0) \qquad \textbf{(EQ. B2.12)}$$

LOW SENSITIVITY (B++): is where the cost of unfunded debt increases 15 basis points. This is the current spread between A and B++ rated bonds for utilities. Under Low Sensitivity (B++), the cost of unfunded debt increases from 6.91% to 7.06%. The overall cost of capital will be as follows for the various capital structures:

Funded Debt		**Unfunded Debt**		**Junior Sub. Deb.**		**Preferred Share**		**Common Equity**		**Cost of Capital**
Cost	**%**	**Cost**	**%**	**Cost**	**%**	**Cost**	**%**	**Cost**	**%**	
10.09	54.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.24	54.7	7.06	5.75	8.72	2.85	7.43	6.70	10.82	30.0	10.00%
10.24	49.7	7.06	5.75	8.72	2.85	7.43	6.70	10.82	35.0	10.03%
10.24	39.7	7.06	5.75	8.72	2.85	7.43	6.70	10.82	45.0	10.09%

Cost of Capital = 9.85% = current state

= (cost of funded debt x percentage of funded debt) + (cost of unfunded debt x percentage of unfunded debt) + (cost of junior subordinated debentures x percentage of junior subordinated debentures) + (cost of preferred share equity x percentage of preferred share equity) + (cost of common equity x percentage of common equity)

= (10.09 x 54.7) + (6.91 x 5.75) + (8.57 x 2.85) + (7.28 x 6.70) + (10.67 x 30.0) **(EQ. B2.13)**

Cost of Capital = 10.00%

= ((10.09 + 0.15) x 54.7) + ((6.91 + 0.15) x 5.75) + ((8.57 + 0.15) x 2.85) + ((7.28 + 0.15) x 6.70) + ((10.67 + 0.15) x 30.0) **(EQ. B2.14)**

Cost of Capital = 10.03%

= ((10.09 + 0.15) x 49.7) + ((6.91 + 0.15) x 5.75) + ((8.57 + 0.15) x 2.85) + ((7.28 + 0.15) x 6.70) + ((10.67 + 0.15) x 35.0) **(EQ.B2.15)**

Cost of Capital = 10.09%

= ((10.09 + 0.15) x 39.7) + ((6.91 + 0.15) x 5.75) + ((8.57 + 0.15) x 2.85) + ((7.28 + 0.15) x 6.70) + ((10.67 + 0.15) x 45.0) **(EQ. B2.16)**

MEDIUM SENSITIVITY (B++): is where the cost of unfunded debt increases 50 basis points. This is halfway between the B++ utility and B++ corporate rated bond yields. Under Medium Sensitivity (B++), the overall cost of capital will be as follows for the various capital structures:

Funded Debt		**Unfunded Debt**		**Junior Sub. Deb.**		**Preferred Share**		**Common Equity**		**Cost of Capital**
Cost	**%**	**Cost**	**%**	**Cost**	**%**	**Cost**	**%**	**Cost**	**%**	
10.09	54.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.59	54.7	7.41	5.75	9.07	2.85	7.78	6.70	11.17	30.0	10.35%
10.59	49.7	7.41	5.75	9.07	2.85	7.78	6.70	11.17	35.0	10.38%
10.59	39.7	7.41	5.75	9.07	2.85	7.78	6.70	11.17	45.0	10.44%

Cost of Capital = 9.85% = current state

= (cost of funded debt x percentage of funded debt) + (cost of unfunded debt x percentage of unfunded debt) + (cost of junior subordinated debentures x percentage of junior subordinated debentures) + (cost of preferred share equity x percentage of preferred share equity) + (cost of common equity x percentage of common equity)

= (10.09 x 54.7) + (6.91 x 5.75) + (8.57 x 2.85) + (7.28 x 6.70) + (10.67 x 30.0) **(EQ. B2.17)**

Cost of Capital = 10.35%

= ((10.09 + 0.50) x 54.7) + ((6.91 + 0.50) x 5.75) + ((8.57 + 0.50) x 2.85) + ((7.28 + 0.50) x 6.70) + ((10.67 + 0.50) x 30.0) **(EQ. B2.18)**

Cost of Capital = 10.38%

= ((10.09 + 0.50) x 49.7) + ((6.91 + 0.50) x 5.75) + ((8.57 + 0.50) x 2.85) + ((7.28 + 0.50) x 6.70) + ((10.67 + 0.50) x 35.0) **(EQ. B2.19)**

Cost of Capital = 10.44%

= ((10.09 + 0.50) x 39.7) + ((6.91 + 0.50) x 5.75) + ((8.57 + 0.50) x 2.85) + ((7.28 + 0.50) x 6.70) + ((10.67 + 0.50) x 45.0) **(EQ. B2.20)**

HIGH SENSITIVITY (B++): is where the cost of unfunded debt increases 85 basis points. This is the current spread between B++ utility and B++ corporate rated bond yields. Under High Sensitivity (B++), the cost of unfunded debt increases from 6.91% to 7.76%. The overall cost of capital will be as follows for the various capital structures:

Funded Debt		**Unfunded Debt**		**Junior Sub. Deb.**		**Preferred Share**		**Common Equity**		**Cost of Capital**
Cost	**%**	**Cost**	**%**	**Cost**	**%**	**Cost**	**%**	**Cost**	**%**	
10.09	54.7	6.91	5.75	8.57	2.85	7.28	6.70	10.67	30.0	9.85%
10.94	54.7	7.76	5.75	9.42	2.85	8.13	6.70	11.52	30.0	10.70%
10.94	49.7	7.76	5.75	9.42	2.85	8.13	6.70	11.52	35.0	10.73%
10.94	39.7	7.76	5.75	9.42	2.85	8.13	6.70	11.52	45.0	10.79%

Cost of Capital = 9.85% = current state

= (cost of funded debt x percentage of funded debt) + (cost of unfunded debt x percentage of unfunded debt) + (cost of junior subordinated debentures x percentage of junior subordinated debentures) + (cost of preferred share equity x percentage of preferred share equity) + (cost of common equity x percentage of common equity)

= (10.09 x 54.7) + (6.91 x 5.75) + (8.57 x 2.85) + (7.28 x 6.70) + (10.67 x 30.0) **(EQ. B2.21)**

Cost of Capital = 10.70%

= ((10.09 + 0.85) x 54.7) + ((6.91 + 0.85) x 5.75) + ((8.57 + 0.85) x 2.85) + ((7.28 + 0.85) x 6.70) + ((10.67 + 0.85) x 30.0) **(EQ. B2.22)**

Cost of Capital = 10.38%

= ((10.09 + 0.85) x 49.7) + ((6.91 + 0.85) x 5.75) + ((8.57 + 0.85) x 2.85) + ((7.28 + 0.85) x 6.70) + ((10.67 + 0.85) x 35.0) **(EQ. B2.23)**

Cost of Capital = 10.44%

= ((10.09 + 0.85) x 39.7) + ((6.91 + 0.85) x 5.75) + ((8.57 + 0.85) x 2.85) + ((7.28 + 0.85) x 6.70) + ((10.67 + 0.85) x 45.0) **(EQ. B2.24)**

Appendix C- Results

Simulation I

Under this scenario there is no change in the risk faced by the Canadian gas transmission industry, no stranded costs, and the regulatory environment remains unchanged. However, gas pipelines are now able to determine their own capital structure within a modest range of the common equity ratio deemed by the NEB. The model is simulated for an A+ and B++ bond rating. Here the focus is on whether slight variations in capital structure affect the cost of capital and the cost of gas transmission. The results are as follows:

SIMULATION 1: SUMMARY OF RESULTS

	Current State	Increase In Common Equity Ratio	Decrease In Common Equity Ratio
Bond Rating	A	A+	B++
Percentage of Funded Debt	54.7%	49.7%	59.7%
Cost of Funded Debt	10.09%	9.97%	10.24%
Percentage of Common Equity	30.0%	35.0%	25.0%
Cost of Common Equity	10.67%	10.55%	10.82%
Cost of Capital	9.85%	9.76%	9.97%
Rate of Return on Rate Base	9.85%	9.76%	9.97%
Equity Component	$274,061,613.60	$309,711,904.80	$238,039,965.20
Utility Income Tax	$102,106,843.48	$129,841,608.82	$74,083,174.33
Return on Rate Base	$731,633,101.15	$724,617,420.93	$740,690,503.26
Net Revenue Requirement	$1,704,363,944.63	$1,725,083,029.75	$1,685,397,677.59
Average cost per km	$119,403.39	$120,854.91	$118,074.66
% Change in Costs[69]		1.20%	-1.13%

[69] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

Simulation Set II

In this case there is a change in risk exposure faced by Canadian gas pipelines. Bond rating agencies react by adjusting the debt leverage benchmark ratios. For this set of simulations the debt leverage benchmark ratios are:

Debt Leverage Ratio	Bond Rating
50%-60%	A
60%-70%	B++

For simulation II the capital structure for A rated bonds is adjusted, but the capital structure for B++ rated bonds is equal to the current capital structure. Furthermore, the debt leverage benchmark ratios are those that are currently used by the CBRS for Canadian oil pipelines. Overall, this is equivalent to decreasing the current debt leverage benchmarks by 10%.

SIMULATION II-A: SUMMARY OF RESULTS

Summary of Variables

Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity (A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Zero probability of stranded costs.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	49.7%	54.7%	49.7%	54.7%	49.7%	54.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	35.0%	30.0%	35.0%	30.0%	35.0%	30.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.88%	10.00%	9.93%	10.35%	9.98%	10.70%
Rate of Return on Rate Base	9.85%	9.88%	10.00%	9.93%	10.35%	9.98%	10.70%
Equity Component	$274,061,614	$313,425,477	$278,220,814	$314,910,906	$287,430,473	$316,693,420	$297,085,760
Utility Income Tax	$102,106,843	$132,730,647	$105,342,566	$133,886,262	$112,507,380	$135,273,000	$120,018,879
Return on Rate Base	$731,633,101	$733,801,827	$742,714,400	$737,515,399	$768,709,404	$741,228,971	$794,704,408
Net Revenue Requirement	$1,704,363,945	$1,737,156,474	$1,718,680,966	$1,742,025,661	$1,751,840,784	$1,747,125,972	$1,785,347,287
Cost per km	$119,403	$121,701	$120,406	$122,042	$122,729	$122,399	$125,077
% Change in Costs[70]		1.89%	0.83%	2.16%	2.71%	2.45%	4.54%

[70] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

SIMULATION II-B: SUMMARY OF RESULTS

Summary of Variables

Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity(A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Risk premium of 250 basis points.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	49.7%	54.7%	49.7%	54.7%	49.7%	54.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	35.0%	30.0%	35.0%	30.0%	35.0%	30.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.88%	10.00%	9.93%	10.35%	9.98%	10.70%
Rate of Return on Rate Base	9.85%	12.38%	12.50%	12.43%	12.85%	12.48%	13.20%
Equity Component	$274,061,614	$313,425,477	$278,220,814	$314,910,906	$287,430,473	$316,693,420	$297,085,760
Utility Income Tax	$102,106,843	$132,730,647	$105,342,566	$133,886,262	$112,507,380	$135,273,000	$120,018,879
Return on Rate Base	$731,633,101	$919,480,427	$928,393,000	$923,193,999	$954,388,004	$926,907,571	$980,383,008
Net Revenue Requirement	$1,704,363,945	$1,922,835,074	$1,904,359,566	$1,927,704,261	$1,937,519,384	$1,932,804,572	$1,971,025,887
Cost per km	$119,403	$134,709	$133,415	$135,050	$135,738	$135,407	$138,085
% Change in Costs[64]		11.36%	10.50%	11.59%	12.03%	11.82%	13.53%

[64] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

SIMULATION II-C: SUMMARY OF RESULTS

Summary of Variables
Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity(A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Risk premium of 500 basis points.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	49.7%	54.7%	49.7%	54.7%	49.7%	54.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	35.0%	30.0%	35.0%	30.0%	35.0%	30.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.88%	10.00%	9.93%	10.35%	9.98%	10.70%
Rate of Return on Rate Base	9.85%	14.88%	15.00%	14.93%	15.35%	14.98%	15.70%
Equity Component	$274,061,614	$313,425,477	$278,220,814	$314,910,906	$287,430,473	$316,693,420	$297,085,760
Utility Income Tax	$102,106,843	$132,730,647	$105,342,566	$133,886,262	$112,507,380	$135,273,000	$120,018,879
Return on Rate Base	$731,633,101	$1,605,159,027	$1,114,071,600	$1,108,872,599	$1,140,066,604	$1,112,586,171	$1,166,061,608
Net Revenue Requirement	$1,704,363,945	$2,108,513,674	$2,090,038,166	$2,113,382,861	$2,123,197,984	$2,118,483,172	$2,156,704,487
Cost per km	$119,403	$147,717	$146,423	$148,058	$148,746	$148,416	$151,093
% Change in Costs[65]		19.17%	18.45%	19.35%	19.73%	19.55%	20.97%

[65] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

SIMULATION II-D: SUMMARY OF RESULTS

Summary of Variables

Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity (A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Risk premium of 750 basis points.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	49.7%	54.7%	49.7%	54.7%	49.7%	54.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	35.0%	30.0%	35.0%	30.0%	35.0%	30.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.88%	10.00%	9.93%	10.35%	9.98%	10.70%
Rate of Return on Rate Base	9.85%	17.38%	17.50%	17.43%	17.85%	17.48%	18.20%
Equity Component	$274,061,614	$313,425,477	$278,220,814	$314,910,906	$287,430,473	$316,693,420	$297,085,760
Utility Income Tax	$102,106,843	$132,730,647	$105,342,566	$133,886,262	$112,507,380	$135,273,000	$120,018,879
Return on Rate Base	$731,633,101	$1,290,837,627	$1,299,750,200	$1,294,551,199	$1,325,745,204	$1,298,264,771	$1,351,740,208
Net Revenue Requirement	$1,704,363,945	$2,294,192,274	$2,275,716,766	$2,299,061,461	$2,308,876,584	$2,304,161,772	$2,342,383,087
Cost per km	$119,403	$160,725	$159,431	$161,066	$161,754	$161,424	$164,101
% Change in Costs[66]		25.71%	25.11%	25.87%	26.18%	26.03%	27.24%

[66] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

SIMULATION II-E: SUMMARY OF RESULTS

Summary of Variables

Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity (A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Risk premium of 1125 basis points.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	49.7%	54.7%	49.7%	54.7%	49.7%	54.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	35.0%	30.0%	35.0%	30.0%	35.0%	30.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.88%	10.00%	9.93%	10.35%	9.98%	10.70%
Rate of Return on Rate Base	9.85%	21.13%	21.25%	21.18%%	21.60%%	21.23%	21.95%
Equity Component	$274,061,614	$313,425,477	$278,220,814	$314,910,906	$287,430,473	$316,693,420	$297,085,760
Utility Income Tax	$102,106,843	$132,730,647	$105,342,566	$133,886,262	$112,507,380	$135,273,000	$120,018,879
Return on Rate Base	$731,633,101	$1,569,355,527	$1,578,268,100	$1,573,069,099	$1,604,263,104	$1,576,782,671	$1,630,258,108
Net Revenue Requirement	$1,704,363,945	$2,572,710,174	$2,554,234,666	$2,577,5779,361	$2,587,394,484	$2,582,679,672	$2,620,900,987
Cost per km	$119,403	$180,238	$178,943	$180,579	$181,266	$180,936	$183,614
% Change in Costs[67]		33.75%	33.27%	33.88%	34.13%	34.01%	34.97%

[67] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

Simulation Set III

Under this scenario there is also a change in risk exposure faced by Canadian gas pipelines. Bond rating agencies react by adjusting the debt leverage benchmark ratios. For this set of simulations the debt leverage benchmark ratios are:

Debt Leverage Ratio	Bond Rating
40%-50%	A
50%-60%	B++

Overall, this is equivalent to decreasing the current debt leverage benchmarks by 20%. This is slightly over halfway between the current Canadian and U.S. debt leverage ratio benchmarks.

SIMULATION III-A: SUMMARY OF RESULTS

Summary of Variables

Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity (A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Zero probability of stranded costs.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	39.7%	49.7%	39.7%	49.7%	39.7%	49.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	45.0%	35.0%	45.0%	35.0%	45.0%	35.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.94%	10.03%	9.99%	10.38%	10.04%	10.73%
Rate of Return on Rate Base	9.85%	9.94%	10.03%	9.99%	10.38%	10.04%	10.73%
Equity Component	$274,061,614	$392,895,918	$318,624,478	$395,124,061	$329,022,479	$396,609,490	$339,791,838
Utility Income Tax	$102,106,843	$194,556,061	$136,775,300	$196,289,484	$144,864,607	$197,445,099	$153,242,817
Return on Rate Base	$731,633,101	$738,258,114	$744,942,543	$741,971,686	$770,937,547	$745,685,258	$796,932,551
Net Revenue Requirement	$1,704,363,945	$1,803,438,175	$1,752,341,843	$1,808,885,170	$1,786,426,154	$1,813,754,357	$1,820,799,368
Cost per km	$119,403	$126,344	$122,765	$126,726	$125,152	$127,067	$127,561
% Change in Costs[68]		5.49%	2.74%	5.78%	4.59%	6.03%	6.39%

[68] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

SIMULATION III-B: SUMMARY OF RESULTS

Summary of Variables

Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity (A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Risk premium of 250 basis points.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	39.7%	49.7%	39.7%	49.7%	39.7%	49.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	45.0%	35.0%	45.0%	35.0%	45.0%	35.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.94%	10.03%	9.99%	10.38%	10.04%	10.73%
Rate of Return on Rate Base	9.85%	12.44%	12.53%	12.49%	12.88%	12.54%	13.23%
Equity Component	$274,061,614	$392,895,918	$318,624,478	$395,124,061	$329,022,479	$396,609,490	$339,791,838
Utility Income Tax	$102,106,843	$194,556,061	$136,775,300	$196,289,484	$144,864,607	$197,445,099	$153,242,817
Return on Rate Base	$731,633,101	$923,936,714	$930,621,143	$927,650,286	$956,616,147	$931,363,858	$982,611,151
Net Revenue Requirement	$1,704,363,945	$1,989,116,775	$1,938,020,443	$1,994,563,770	$1,972,104,754	$1,999,432,957	$2,006,477,968
Cost per km	$119,403	$139,352	$135,773	$139,734	$138,161	$140,075	$140,569
% Change in Costs[69]		14.32%	12.06%	14.55%	13.58%	14.76%	15.06%

[69] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

SIMULATION III-C: SUMMARY OF RESULTS

Summary of Variables

Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity (A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Risk premium of 500 basis points.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	39.7%	49.7%	39.7%	49.7%	39.7%	49.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	45.0%	35.0%	45.0%	35.0%	45.0%	35.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.94%	10.03%	9.99%	10.38%	10.04%	10.73%
Rate of Return on Rate Base	9.85%	14.94%	15.03%	14.99%	15.38%	15.04%	15.73%
Equity Component	$274,061,614	$392,895,918	$318,624,478	$395,124,061	$329,022,479	$396,609,490	$339,791,838
Utility Income Tax	$102,106,843	$194,556,061	$136,775,300	$196,289,484	$144,864,607	$197,445,099	$153,242,817
Return on Rate Base	$731,633,101	$1,109,615,314	$1,116,299,743	$1,113,328,886	$1,142,294,747	$1,117,042,458	$1,168,289,751
Net Revenue Requirement	$1,704,363,945	$2,174,795,375	$2,123,699,043	$2,180,242,370	$2,157,783,354	$2,185,111,557	$2,192,156,568
Cost per km	$119,403	$152,361	$148,781	$152,742	$151,169	$153,083	$153,577
% Change in Costs[70]		21.63%	19.75%	21.83%	21.01%	22.00%	22.25%

[70] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

SIMULATION III-D: SUMMARY OF RESULTS

Summary of Variables

Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity(A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Risk premium of 750 basis points.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	39.7%	49.7%	39.7%	49.7%	39.7%	49.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	45.0%	35.0%	45.0%	35.0%	45.0%	35.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.94%	10.03%	9.99%	10.38%	10.04%	10.73%
Rate of Return on Rate Base	9.85%	17.44%	17.53%	17.49%	17.88%	17.54%	18.23%
Equity Component	$274,061,614	$392,895,918	$318,624,478	$395,124,061	$329,022,479	$396,609,490	$339,791,838
Utility Income Tax	$102,106,843	$194,556,061	$136,775,300	$196,289,484	$144,864,607	$197,445,099	$153,242,817
Return on Rate Base	$731,633,101	$1,295,293,914	$1,301,978,343	$1,299,007,486	$1,327,973,347	$1,302,721,058	$1,353,968,351
Net Revenue Requirement	$1,704,363,945	$2,360,473,975	$2,309,377,643	$2,365,920,970	$2,343,461,954	$2,370,790,157	$2,377,835,168
Cost per km	$119,403	$165,369	$161,789	$165,750	$164,177	$166,092	$166,585
% Change in Costs[71]		27.80%	26.20%	27.96%	27.27%	28.11%	28.32%

[71] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

SIMULATION III-E: SUMMARY OF RESULTS

Summary of Variables

Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity(A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Risk premium of 1125 basis points.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	39.7%	49.7%	39.7%	49.7%	39.7%	49.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	45.0%	35.0%	45.0%	35.0%	45.0%	35.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.94%	10.03%	9.99%	10.38%	10.04%	10.73%
Rate of Return on Rate Base	9.85%	21.19%	21.28%	21.24%	21.63%	21.29%	21.98%
Equity Component	$274,061,614	$392,895,918	$318,624,478	$395,124,061	$329,022,479	$396,609,490	$339,791,838
Utility Income Tax	$102,106,843	$194,556,061	$136,775,300	$196,289,484	$144,864,607	$197,445,099	$153,242,817
Return on Rate Base	$731,633,101	$1,573,811,814	$1,580,496,243	$1,577,525,386	$1,606,491,247	$1,581,238,958	$1,632,486,251
Net Revenue Requirement	$1,704,363,945	$2,638,991,875	$2,587,895,543	$2,644,438,870	$2,621,979,854	$2,649,308,057	$2,656353,068
Cost per km	$119,403	$184,881	$181,301	$185,263	$183,689	$185,604	$186,097
% Change in Costs[72]		35.42%	34.14%	35.55%	35.00%	35.67%	35.84%

[72] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

Simulation Set IV

Here there is a further change in risk exposure faced by Canadian gas transmission companies. Bond rating agencies react by adjusting the debt leverage benchmark ratios. For this set of simulations the debt leverage benchmark ratios are:

Debt Leverage Ratio	Bond Rating
30%-40%	A
40%-50%	B++

Overall, this is equivalent to decreasing the current debt leverage benchmarks approximately 30%. This is approximately the debt leverage ratios currently observed in the U.S. gas transmission industry.

SIMULATION IV-A: SUMMARY OF RESULTS

Summary of Variables

Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity(A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Zero probability of stranded costs.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	29.7%	39.7%	29.7%	39.7%	29.7%	39.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	55.0%	45.0%	55.0%	45.0%	55.0%	45.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.99%	10.09%	10.04%	10.44%	10.09%	10.79%
Rate of Return on Rate Base	9.85%	9.99%	10.09%	10.04%	10.44%	10.09%	10.79%
Equity Component	$274,061,614	$472,143,544	$398,837,633	$473,851,787	$412,206,492	$476,079,930	$425,501,080
Utility Income Tax	$102,106,843	$256,208,133	$199,178,522	$257,537,091	$209,579,059	$259,270,514	$219,921,815
Return on Rate Base	$731,633,101	$741,971,686	$749,398,830	$745,885,258	$775,579,059	$749,398,830	$801,388,838
Net Revenue Requirement	$1,704,363,945	$1,868,803,819	$1,819,201,352	$1873,846,349	$1,855,596,893	$1,879,293,343	$1,891,934,653
Cost per Km	$119,403	$130,924	$127,449	$131,277	$129,998	$131,658	$132,544
% Change in Costs[73]		8.80%	6.31%	9.04%	8.15%	9.31%	9.91%

[73] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

SIMULATION IV-B: SUMMARY OF RESULTS

Summary of Variables
Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity(A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Risk premium of 250 basis points.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	29.7%	39.7%	29.7%	39.7%	29.7%	39.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	55.0%	45.0%	55.0%	45.0%	55.0%	45.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.99%	10.09%	10.04%	10.44%	10.09%	10.79%
Rate of Return on Rate Base	9.85%	12.49%	12.59%	12.54%	12.94%	12.59%	13.29%
Equity Component	$274,061,614	$472,143,544	$398,837,633	$473,851,787	$412,206,492	$476,079,930	$425,501,080
Utility Income Tax	$102,106,843	$256,208,133	$199,178,522	$257,537,091	$209,579,059	$259,270,514	$219,921,815
Return on Rate Base	$731,633,101	$927,650,286	$935,077,430	$931,363,858	$961,072,434	$935,077,430	$987,067,438
Net Revenue Requirement	$1,704,363,945	$2,054,482,419	$2,004,879,952	$2,059,524,949	$2,041,275,493	$2,064,971,943	$2,077,613,253
Cost per km	$119,403	$143,932	$140,457	$144,285	$143,007	$144,667	$145,552
% Change in Costs[74]		17.04%	14.99%	17.24%	16.50%	17.46%	17.97%

[74] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

SIMULATION IV-C: SUMMARY OF RESULTS

Summary of Variables

Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity(A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Risk premium of 500 basis points.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	29.7%	39.7%	29.7%	39.7%	29.7%	39.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	55.0%	45.0%	55.0%	45.0%	55.0%	45.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.99%	10.09%	10.04%	10.44%	10.09%	10.79%
Rate of Return on Rate Base	9.85%	14.99%	15.09%	15.04%	15.44%	15.09%	15.79%
Equity Component	$274,061,614	$472,143,544	$398,837,633	$473,851,787	$412,206,492	$476,079,930	$425,501,080
Utility Income Tax	$102,106,843	$256,208,133	$199,178,522	$257,537,091	$209,579,059	$259,270,514	$219,921,815
Return on Rate Base	$731,633,101	$1,113,328,886	$1,120,756,030	$1,117,042,458	$1,146,751,074	$1,120,756,030	$1,172,746,038
Net Revenue Requirement	$1,704,363,945	$2,240,161,019	$2,190,558,552	$2,245,203,549	$2,226,954,093	$2,250,650,543	$2,263,291,853
Cost per km	$119,403	$156,940	$153,465	$157,293	$156,015	$157,675	$158,560
% Change in Costs[75]		23.92%	22.20%	24.09%	23.47%	24.27%	24.70%

[75] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

SIMULATION IV-D: SUMMARY OF RESULTS

Summary of Variables

Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity(A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Risk premium of 750 basis points.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	29.7%	39.7%	29.7%	39.7%	29.7%	39.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	55.0%	45.0%	55.0%	45.0%	55.0%	45.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.99%	10.09%	10.04%	10.44%	10.09%	10.79%
Rate of Return on Rate Base	9.85%	17.49%	17.59%	17.54%	17.94%	17.59%	18.29%
Equity Component	$274,061,614	$472,143,544	$398,837,633	$473,851,787	$412,206,492	$476,079,930	$425,501,080
Utility Income Tax	$102,106,843	$256,208,133	$199,178,522	$257,537,091	$209,579,059	$259,270,514	$219,921,815
Return on Rate Base	$731,633,101	$1,299,007,486	$1,306,434,630	$1,302,721,058	$1,332,429,634	$1,306,434,630	$1,358,424,638
Net Revenue Requirement	$1,704,363,945	$2,425,839,619	$2,376,237,152	$2,430,882,149	$2,412,632,693	$2,436,329,143	$2,448,970,453
Cost per Km	$119,403	$169,948	$166,473	$170,301	$169,623	$170,683	$171,569
% Change in Costs[76]		29.74%	28.27%	29.89%	29.36%	30.04%	30.40%

[76] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

SIMULATION IV-E: SUMMARY OF RESULTS

Summary of Variables
Low Sensitivity (A): No change in the cost rate of capital instruments.
Low Sensitivity (B++): Increase in the cost rate of capital instruments by 15 basis points.
Medium Sensitivity(A): Increase in the cost rate of capital instruments by 5 basis points.
Medium Sensitivity (B++): Increase in the cost rate of capital instruments by 50 basis points.
High Sensitivity (A): Increase in the cost rate of capital instruments by 10 basis points.
High Sensitivity (B++): Increase in the cost rate of capital instruments by 85 basis points.
Stranded Costs: Risk premium of 1125 basis points.

	Current State	Low Sensitivity (A)	Low Sensitivity (B++)	Medium Sensitivity (A)	Medium Sensitivity (B++)	High Sensitivity (A)	High Sensitivity (B++)
Bond Rating	A	A	B++	A	B++	A	B++
Percentage of Funded Debt	54.7%	29.7%	39.7%	29.7%	39.7%	29.7%	39.7%
Cost of Funded Debt	10.09%	10.09%	10.24%	10.14%	10.59%	10.19%	10.94%
Percentage of Common Equity	30.0%	55.0%	45.0%	55.0%	45.0%	55.0%	45.0%
Cost of Common Equity	10.67%	10.67%	10.82%	10.72%	11.17%	10.77%	11.52%
Cost of Capital	9.85%	9.99%	10.09%	10.04%	10.44%	10.09%	10.79%
Rate of Return on Rate Base	9.85%	21.24%	21.34%	21.29%	21.69%	21.34%	22.04%
Equity Component	$274,061,614	$472,143,544	$398,837,633	$473,851,787	$412,206,492	$476,079,930	$425,501,080
Utility Income Tax	$102,106,843	$256,208,133	$199,178,522	$257,537,091	$209,579,059	$259,270,514	$219,921,815
Return on Rate Base	$731,633,101	$1,577,525,386	$1,584,952,530	$1,581,238,958	$1,610,947,534	$1,584,952,530	$1,636,942,538
Net Revenue Requirement	$1,704,363,945	$2,704,357,519	$2,654,755,052	$2,709,400,049	$2,691,150,593	$2,714,847,043	$2,727,488,353
Cost per km	$119,403	$189,460	$185,985	$189,814	$188,535	$190,195	$191,081
% Change in Costs[77]		36.98%	35.80%	37.09%	36.67%	37.22%	37.51%

[77] % change in costs = 1 - (current cost per km ÷ simulated cost per km)

Appendix D

This section outlines the calculations for the average toll. Note that all data is based on TCPL.

Average Load Factor = 95%[78]

Revenue Requirement = $1,704,363,945[79]

Capacity = 7.313 Bcf/d[80]

Average Toll = Revenue Requirement ÷ (Capacity x Load Factor)

= $1,704,363,945 ÷ (7.313 Bcf/d x 95%) **(EQ.D1)**

= $0.245/Mcf[81]

If there is an increase in the cost of gas transmission of 2% and the load factor remains at 95%:

Average Toll = ($1,704,363,945 ÷ (7.313 Bcf/d x 95%)) x 0.02 **(EQ.D2)**

= $0.25/Mcf

Change in tolls = $0.005/Mcf

If there is an increase in the cost of gas transmission of 5% and the load factor remains at 95%:

Average Toll = ($1,704,363,945 ÷ (7.313 Bcf/d x 95%)) x 0.05 **(EQ.D3)**

= $0.258/Mcf

Change in tolls = $0.013/Mcf

If there is an increase in the cost of gas transmission of 5% and the load factor declines to 90%:

Average Toll = ($1,704,363,945 ÷ (7.313 Bcf/d x 90%)) x 0.05 **(EQ.D4)**

= $0.272/Mcf

Change in tolls = $0.027/Mcf

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[78] This is the average load factor for the TCPL mainline from 1996-1998 as calculated from Table D1.
[79] Source: National Energy Board (1997b: 4).
[80] Source: Natural Gas Analyst (1998).
[81] TCPL's current toll from Empress to Emerson is approximately $0.26/Mcf.

If there is an increase in the cost of gas transmission of 10% and the load factor remains at 95%:

Average Toll = (\$1,704,363,945 ÷ (7.313 Bcf/d x 95%)) x 0.10 **(EQ.D5)**

= \$0.27/Mcf

Change in tolls = \$0.0245/Mcf

If there is an increase in the cost of gas transmission of 10% and the load factor declines to 90%:

Average Toll = (\$1,704,363,945 ÷ (7.313/Bcf/d x 90%)) x 0.10 **(EQ.D6)**

= \$0.285/Mcf

Change in tolls = \$0.0385/Mcf

If there is an increase in the cost of gas transmission of 15% and the load factor remains at 95%:

Average Toll = (\$1,704,363,945 ÷ (7.313 Bcf/d x 95%)) x 0.15 **(EQ.D7)**

= \$0.282/Mcf

Change in tolls = \$0.037/Mcf

If there is an increase in the cost of gas transmission of 15% and the load factor declines to 90%:

Average Toll = (\$1,704,363,945 ÷ (7.313 Bcf/d x 90%)) x 0.15 **(EQ.D8)**

= \$0.298/Mcf

Change in tolls = \$0.0525/Mcf

TABLE D1: RECENT VOLUMES TRANSPORTED BY TCPL (average Bcf/d)

Receipts

	Empress	Saskatchewan	Total Receipts	Capacity	Load Factor
June 1998	6.316	.407	6.723	7.313	92%
May 1998	6.224	.410	6.634	7.313	91%
April 1998	6.687	.411	7.098	7.313	97%
March 1998	6.710	.479	7.189	7.313	98%
February 1998	7.653	.500	8.153	7.313	111%
January 1998	6.931	1.226	8.157	7.313	112%
December 1997	6.671	1.286	7.957	7.313	109%
November 1997	6.498	1.112	7.610	7.313	104%
October 1997	6.261	1.156	7.417	7.313	101%
September 1997	5.824	2.616	8.440	7.313	115%
August 1997	5.986	.367	6.353	7.313	87%
July 1997	6.004	.409	6.413	7.313	88%
June 1997	5.867	.434	6.301	7.313	86%
May 1997	6.054	.489	6.543	7.313	89%
April 1997	6.339	.453	6.792	7.313	93%
March 1997	6.221	.432	6.653	7.313	91%
February 1997	6.441	.371	6.812	7.313	93%
January 1997	6.639	.626	7.265	7.313	99%
December 1996	6.475	.483	6.958	7.313	95%
November 1996	6.282	.459	6.741	7.313	92%
October 1996	6.071	.416	6.487	7.313	89%
September 1996	5.650	.429	6.079	7.313	83%
August 1996	6.098	.438	6.536	7.313	89%
July 1996	5.924	.423	6.347	7.313	87%
June 1996	5.812	.408	6.220	7.313	85%

Source: Natural Gas Analyst (1998)