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VIA COURIER AND RESS

April 17, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: Ontario Energy Board (the "Board") File No. EB-2009-0084
The Cost of Capital in Current Economic and Financial Market Conditions
Written Comments of Enbridge Gas Distribution Inc. ("Enbridge")

Pursuant to the Board's March 16, 2009 letter in the above noted proceeding, please find attached Enbridge's written comments.

Further to the Board's direction, Enbridge has made this submission using the RESS and has sent 3 hard copies to the Board via courier.

Sincerely,

Lesley Austin

Lesley Austin
Regulatory Coordinator

Attachment

cc: David Stevens, Aird & Berlis LLP (via email)
EB-2009-0084 Interested Parties (via email)

THE COST OF CAPITAL IN CURRENT ECONOMIC
AND FINANCIAL MARKET CONDITIONS
ENBRIDGE GAS DISTRIBUTION INC. WRITTEN SUBMISSION

EB-2009-0084

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THE COST OF CAPITAL IN CURRENT ECONOMIC AND FINANCIAL MARKET CONDITIONS

ONTARIO ENERGY BOARD
EB-2009-0084

WRITTEN SUBMISSION OF ENBRIDGE GAS DISTRIBUTION INC.

April 17, 2009

A. EXECUTIVE SUMMARY

As a party whose Cost of Capital is set by the Ontario Energy Board ("OEB", or the "Board"), Enbridge Gas Distribution Inc. ("EGD", or the "Company") is pleased to present a submission in this consultative process being part of the proceeding EB-2009-0084: THE COST OF CAPITAL IN CURRENT ECONOMIC AND FINANCIAL MARKET CONDITIONS, initiated under the Board's own motion.

EGD agrees with the Board that economic and financial market conditions have highlighted issues with the Cost of Capital determination for Ontario's utilities. EGD's submission aims to provide information to assist the Board in assessing the need for change, the magnitude of such changes, and the way in which changes should be made. A viable and sustainable energy industry is of paramount importance and achievement of the Fair Return Standard ("FRS") in the determination of Cost of Capital is fundamental to this goal.

The Board is seeking input on five specific questions. The objective of this submission is to provide clear answers to those questions. The Company notes, however, that it is important to consider the entire submission within the appropriate context. This submission provides the context that underpins the following high level responses to the Board's questions:

Question #1: How do the current economic and financial conditions affect the variables used by the Board's Cost of Capital methodology?

Current economic and financial market conditions serve to highlight and exacerbate underlying systemic problems with a formula that provides for returns that fall short of any reasonable interpretation of the FRS.

Question #2: Are the values produced by the Board's Cost of Capital methodology and the relationships between them reasonable?

No. The values produced by the Cost of Capital methodology do not relate to each other in an appropriate manner. Structural changes in the primary variable, government bond yields, have eroded the proper relationship between fair return on equity ("ROE") and business risks, credit, and capital market conditions.

Question #2.1: What are the implications to a distributor of the Cost of Capital parameter values being too low?

The implications are that the results violate a key mandate of the Board, namely the FRS. Further, Ministerial objectives to foster infrastructure investment in the province cannot be accomplished with returns below the FRS.

Question #3: What adjustments should be made to the Cost of Capital parameter values to compensate or correct for the current economic and financial conditions?

The Board should, as an interim measure, immediately adjust ROEs to provide returns that are reasonable on the basis of U.S. LDC benchmark returns and the recent Trans-Quebec and Maritimes Pipeline Inc. ("TQM") Decision (i.e., an increase of at least 200 to 300 basis points to ROE for Ontario's utilities).

Question #4: Going forward, should the Board change the timing of its Cost of Capital determination?

EGD believes that the timing for Cost of Capital determinations should facilitate the timing of utility rate applications. The timing should be consistent from year to year and, to the extent possible, should allow for the use of the most recently available data, while still permitting enough time for a utility to assemble its rate application.

Question #5: Are there any other key issues that should be considered if the Board were to adjust any or all of the Cost of Capital parameter values?

EGD's view is that any interim adjustments to the Cost of Capital should be seen as a first step towards a more comprehensive review of the issues. A single variable impacts the formula's results while a wide variety of business variables can affect the actual Cost of Capital. These issues cannot be fully and fairly addressed within the scope and timing of this consultative process. A variety of factors, such as the globalization of capital flows, spreads between formula ROE and the market cost of debt, spreads between Canadian and U.S. allowed ROEs, and regulatory developments such as the National Energy Board's (NEB) TQM Decision, the Alberta Generic Cost of Capital proceeding, and the NEB's call for submissions to review its own ROE formula, highlight that the current formulaic approach is not producing reasonable results and does not meet the FRS. This has also been the subject of recent reports by the Canadian Gas Association ("CGA"), the American Gas Foundation, and Concentric Energy Advisors ("Concentric"). EGD submits, that the Board should initiate a formal proceeding, separate from this consultative process, to comprehensively review the mechanisms as set out in the Board's "Draft Guidelines On a Formula-Based Return on Common Equity for Regulated Utilities", dated March 1997.

B. DETAILED RESPONSES TO OEB QUESTIONS

1. EGD's detailed responses to the Board's questions are set out below. In addition, EGD has asked two experts to prepare comments about issues related to these questions. Concentric has prepared a report that examines current economic and financial conditions, including changes in financial conditions and the business environment since the formula's inception, and details the shortcomings of the Board's current formula-based Cost of Capital methodology. The Brattle Group has prepared a report that speaks to a changed business environment since the formula's adoption and to the relevance of the recent TQM Decision for Ontario's utilities. These reports are filed as Appendices 1 and 2 to this submission, respectively.

Question #1: How do the current economic and financial conditions affect the variables used by the Board's Cost of Capital methodology?

2. The only active variable in the Board's Cost of Capital methodology is the long Canada bond rate. Comments on other issues that affect the relevance or reasonableness of the Board's formula can be found in subsequent responses.

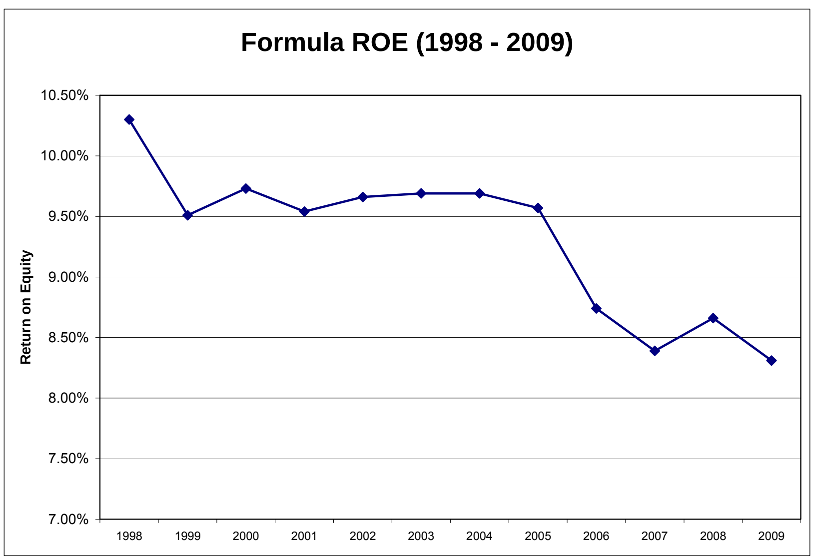
3. Current financial market conditions exacerbate issues with the Board's Cost of Capital Methodology as defined by the Board's "Draft Guidelines On a Formula-Based Return on Common Equity for Regulated Utilities", released in 1997. Declining government bond rates have caused the ROE to trend lower since the formula's inception, even while the demands for capital have significantly increased. Currently, tightening credit market conditions have raised corporate debt rates, while government bond rates remain low. In the Board's most recent determination of the parameter values for electricity LDCs, the spread between the cost of equity and the cost of debt is a mere 39 basis points. There is no capital market justification for this erosion of the equity risk premium.

4. The Company believes that the real cost of equity is in fact increasing. Intuitively, as the cost of debt increases, the cost of equity also increases. However, since long Canada bond rates and corporate debt rates are diverging, the very opposite is occurring.

5. The ROE formula, which is the same for both electric and gas LDCs, is calculated as a function of the change in long Canada bond rates over time. Differences between any utilities' ROE calculation can be attributed solely to the timing of the calculation.[1]

6. The capital structure for electric and gas LDCs does not change according to a formula. The gas utilities have their capital structures fixed at a 36% deemed equity ratio. The electric LDCs have been moving their deemed equity ratios toward a 40% level since 2008.

7. The graphic below illustrates the decline in the formula allowed ROE since its inception.



[1] The ROE formula for the gas and electric utilities were established as follows:
Gas Utilities: ROE = 10.65 + 0.75 * (Long Bond Forecast – 7.25)
Electric Utilities: ROE = 9.35 + 0.75 * (Long Bond Forecast – 5.50)
Note that the resulting ROEs are nearly identical using the same Long Bond Forecast. The difference in parameter values reflects the difference in the timing of creation of the formula. The gas utility formula was created in 1997 with a long bond rate of 7.25%; the electric utility formula was created in 1999 with a long bond rate of 5.50%.

8. It is clear that declining bond yields have resulted in a steady and unnatural decline in allowed ROE levels for LDCs. This is true not only for current economic and financial conditions, but through all economic and financial conditions experienced since the formula was adopted. In the Company's view, current economic and financial conditions are simply highlighting and exacerbating problems with the formulaic methodology, due to its reliance on a single variable whose behaviour has structurally changed over the past 12 years.

9. The interest rate environment today is very different from that which existed in 1997. For one, inflation targeting by the Bank of Canada is now well established as a central function of monetary policy. In 1997, inflation targeting was still in its infancy in Canada. As a result of inflation targeting, inflation rates in Canada have declined from double digit levels in the 1980s to low and stable rates of between 1 to 3% per year. With reduced inflation levels and volatility, bond yields will continue to remain low, despite changes in the capital markets.

10. Another factor that has changed the interest rate landscape is the success the government of Canada has had in virtually eliminating the budget deficits that were so common for years prior to the creation of the ROE formula in Ontario. In the TQM Decision, the NEB observed this change as a key factor that has changed the interest rate environment in Canada.

11. The TD Economics Group examines these and other changes to the interest rate environment in their report entitled <u>The Shape of Yields to Come: An Outlook for U.S. and Canadian Interest Rates to 2020</u>, published June 21, 2007, which is included as Item 1 in the accompanying Reference Materials CD. The TD Economics Group concludes that these structural changes will result in much lower bond yield levels in the future.

12. Current financial market conditions are such that equity investors are demanding higher returns for a given level of risk. As such, linking utilities' equity returns

directly to risk free interest rates has resulted in a divergence of return from risk. That is, allowed returns for formula-based utilities are declining with lower interest rates, while at the same time equity investors are demanding greater return per unit of risk.

13. Changed economic and financial conditions since 1997, and current economic and financial conditions, indicate that the only variable used in the Board's Cost of Capital formula has structurally changed. This is not a problem that will correct itself as the Bank of Canada continues its inflation targeting regime and as governments work to avoid persistent budget deficits. If left unchanged, the current formulaic approach will almost certainly result in continuously low Cost of Capital determinations, which, as described in the following responses, do not meet the FRS.

Question #2: Are the values produced by the Board's Cost of Capital methodology and the relationships between them reasonable?

14. The values produced by the Board's Cost of Capital methodology are not reasonable, nor do they relate to one another in an appropriate way. First, the formula results do not meet the FRS. Second, the results do not account for changing utility business risks since the adoption of the ROE formula. Third, use of the formula has resulted in declining spreads between equity and the market cost of debt, to the point where they are now illogically small.

15. The FRS is an established principle that all regulators in Canada must apply in assessing the Cost of Capital. A comprehensive discussion of the FRS and its application in Canada can be found in the recent report written by Former Justice of the Supreme Court of Canada, the Honourable John C. Major, and Former Chair of the NEB, Roland Priddle. Their report titled, The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications, was published in March 2008, and is included as Item 2 in the accompanying Reference Materials CD.

16. In general, the FRS aims to ensure that a utility is able to secure a fair return on capital, and is defined by three distinct tests. Specifically, utilities should be able to attract capital at reasonable terms, maintain financial integrity, and earn a comparable return commensurate with the return on investments of similar risk. Returns associated with the formula fail the comparable returns test.

17. The NEB reiterated the FRS principles in its recent TQM Decision. They also reiterated the Supreme Court of Canada's finding that the FRS must be guided by the three tests, and as a matter of law, is not to be evaluated by considering the resulting impact on rates. The NEB found that the formula did not result in a fair return for TQM and chose to depart from the use of that formula. Using the same analysis, it can be said that the OEB's formula, which is the same as the NEB formula, does not result in fair returns for Ontario's utilities.

18. To assess the reasonableness of the formula's result, one must compare its returns to those available for investments of similar risk. In the TQM case, the NEB ruled that the use of U.S. entities was appropriate for this purpose. The NEB found that although there are some differences in U.S. and Canadian regulatory frameworks, the similarities outweigh the differences. For example, both countries have similar regulatory models, similar regulatory goals and policies, and operate within a common market for commodities, and more specifically natural gas.

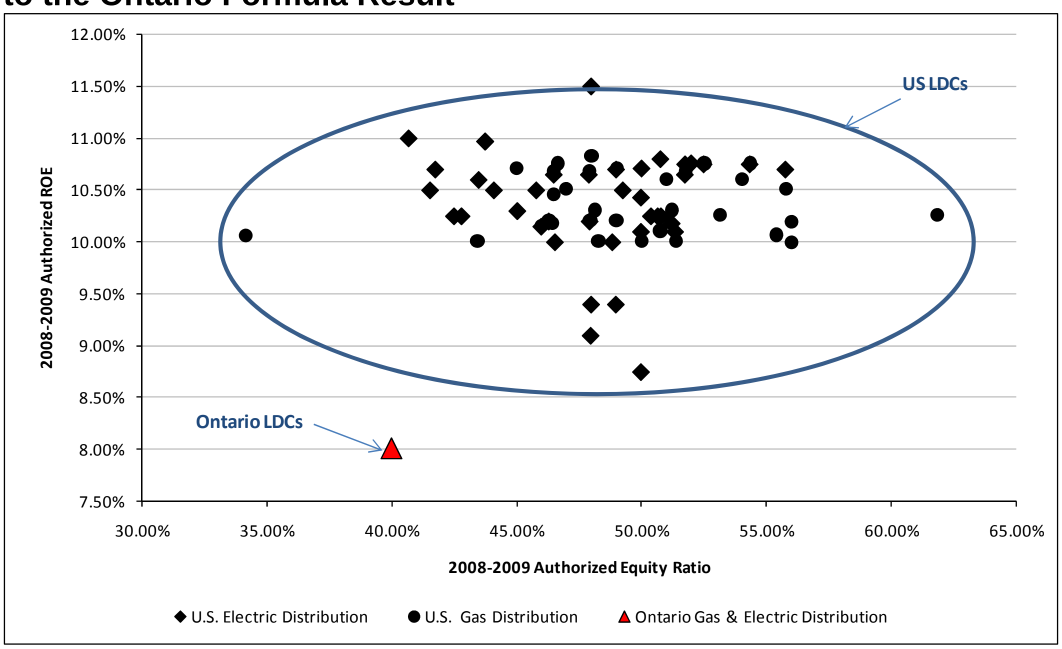
19. The NEB also concluded that comparability to U.S. firms made sense given the increasing globalization, or North Americanization, of capital flows. As funds flow more freely between the countries, it becomes imperative that investors in Canada have an opportunity to earn similar rates of return for investments of similar risk. They also pointed out that changed tax policies in Canada have increased the momentum of capital flows between the countries.

20. Further discussion of the appropriateness of using U.S. LDC returns as relevant comparators to regulated utilities in Ontario was provided in a recent Concentric

report commissioned by the OEB in 2007, A Comparative Analysis of Return on Equity of Natural Gas Utilities. A copy of this report is included as Item 3 in the accompanying Reference Materials CD. In that report, Concentric sought to explain the divergence in returns between U.S. and Ontario LDCs and concluded that there are, in fact, not any significant differences in risk between LDCs in the two countries, which would indicate they are relevant for comparison purposes.

21. In the report that it prepared for EGD to assist with this proceeding, Concentric upholds that there are no appreciable differences in regulatory risk, financial risk, operating characteristics, tax structure, legislation, oversight, or frequency of ROE decisions to justify the gap between U.S. and Ontario ROE awards. Concentric provides a compelling case showing that the Canadian and U.S. markets move tandem, that Canadian and U.S. interest rates and corporate debt rates are closely linked, and that there are close business relationships between the two countries, with the U.S. being Canada's single biggest trading partner.

Comparison of U.S. Gas and Electric Utility ROEs and Equity Ratios to the Ontario Formula Result



Source: Concentric Energy Advisors, The Cost of Capital in Current Economic and Financial Market Conditions, prepared for Enbridge Gas Distribution, April 2009

22. The scatter graph above prepared by Concentric, illustrates the differences in Cost of Capital parameters for U.S. and Ontario utilities. An examination of U.S. electric and gas LDC returns reveals an average ROE of between 10.0% to 11.0%. This compares with the Board's computation of 8.01% for the electric LDCs in 2009 using Ontario's formula. Furthermore, U.S. LDCs typically employ equity ratios of between 45 to 55%, compared to 36% for Ontario's gas utilities and 40% for Ontario's electric utilities.

23. In summary, it is clear (from the NEB's TQM Decision and from Concentric's reports) that there is a solid basis for comparing the returns of U.S. and Canadian LDCs. As seen from the chart above, when that comparison is undertaken it is unambiguous that the differences in returns are both unreasonable and significant.

24. The second reason the ROE formula results are not reasonable relates to changes in the business environment facing Ontario's utilities, as compared to the 1990s, when the Cost of Capital methodology was adopted.

25. Some of the changed business risks facing utilities are common across both gas and electricity, while some are more specific in nature. Risks that affect both electricity and natural gas LDCs include aging infrastructure in combination with significant customer growth and increased demand for power generation. These demands have tremendously increased the capital pressures on both types of systems, requiring significant amounts of infrastructure investment. Greater attention to conservation and government policies promoting conservation also increase risk for the Province's utilities.

26. For the natural gas sector, the price environment has significantly changed since 1997. Higher absolute price levels and greater price volatility have significantly affected demand. Higher, more volatile prices and a growing conservation movement have resulted in declining average uses across Ontario. These and other economic factors, such as the appreciation of the Canadian dollar, have resulted in industrial demand destruction. The changing profile of the housing

market, with a trend towards smaller family dwellings has also changed the business environment. In addition, the business environment has been affected by improving appliance efficiencies, better building codes, and a greater availability of alternative fuels since 1997.

27. The electric LDCs face higher business risks as well. For one, electricity consumption has historically grown in demand every year, due to a very wide array of end use applications, which has put tremendous stress on their ability to provide economic and reliable service. Electric LDCs have also seen higher and more volatile commodity prices, due in part to the higher and more volatile natural gas prices mentioned above. Furthermore, the level of investment that will be required to meet the province's Green Energy mandate and electricity reliability goals can introduce even more risk and uncertainty.

28. The fact that the ROE formula generates consistently declining ROEs as government bond rates stay low, and pays no regard to these increasing risks, is further demonstration that the values produced by the Board's Cost of Capital methodology are not reasonable.

29. A third reason the Board's Cost of Capital methodology results are not reasonable is that the formula has resulted in steadily declining spreads between the cost of equity and the market cost of debt. The product of tightening credit markets has been higher corporate debt rates, as indicated in Appendices 1 and 2, while allowed ROE levels have trended down.

30. Further demonstration of this fact is obtained by the Board's computation of the cost of debt for electric LDCs from 2006 to 2009. In 2006, the Board calculated the cost of debt at 5.80% for utilities with rate base greater than $1 billion. For 2009, the Board has calculated the cost of debt for all electric utilities as 7.62%, an increase of 182 basis points. At the same time the cost of equity has decreased over the same period from 9.00% to 8.01%, a decline of 99 basis points. As a result the

premium of equity to debt has decreased from 320 basis points in 2006 to just 39 basis points in 2009, as the Board pointed out in its letter dated March 16th, 2009.

31. These trends cannot be taken lightly, as their impact could threaten capital attraction and financial integrity for utilities, both of which are central aspects of the FRS. The credit rating assigned by ratings agencies typically analyze certain financial metrics and underlying business risks to assign a rating, which then directly impacts the cost at which that utility is able to obtain debt financing. The financial metrics that underpin ratings most often relate to capital ratios, such as debt-to-total capital, and interest coverage ratios, such as earnings before interest and taxes to interest payments. These measures provide a sense of both exposure to debt and the agility with which a company is able to continue to meet debt obligations in changing economic environments. With spreads between equity and debt decreasing, utilities could see both declining earnings and increasing interest obligations, leading to deterioration in interest coverage ratios. With a high exposure to debt, fixed capital ratios, and increasing business risks, utilities may face credit downgrades. Credit downgrades could then affect a utility's ability to attract capital at reasonable terms, in which case, could even threaten a utility's financial integrity.

32. A fourth reason why the Board's Cost of Capital methodology results are not reasonable is that the application of the formula has resulted in reduced ROEs, at a time when market risk premiums are increasing. As Concentric points out in Appendix 1, capital market analysts are commenting that while the formulaic methodology is continuing to indicate a declining cost of equity, logic suggests that the opposite is in fact true. In other words, the current formulaic approach, which results in low and/or declining ROEs, does not reflect the increased risk premiums that are leading investors to demand higher returns.

33. In summary, the Company contends that the Cost of Capital parameter value results and relationships among the parameter values are not reasonable. The

changing structure of the interest rate environment and the changing nature of utility business risks have rendered the current relationships between ROE and long bond yields, set out in the OEB's current Cost of Capital methodology, invalid. As a result, the OEB's current Cost of Capital methodology fails to meet the FRS and it produces results that are not in line with returns of investments of similar risk.

Question #2.1: What are the implications to a distributor of the Cost of Capital parameter values being too low?

34. The single biggest implication of the Cost of Capital parameter values being too low is that they have resulted in values that are not reasonable and fail to meet the FRS. The Board has a responsibility to maintain a viable industry and to balance the interests of the consumer and the regulated utility, resulting in fair and reasonable outcomes for both. Continuing to set Cost of Capital parameter values that are objectively and comparatively too low runs counter to this important Board responsibility.

35. Utilities in Ontario continue to invest funds to build Ontario's energy infrastructure, however, this must not be presumed to be indicative of fair or acceptable returns. Ontario's utilities will continue to strive for safe and reliable networks, and adhere to franchise and other agreements. Utilities continue to make these investments because the damage and the costs could be profound if they did not. However, simply because the utilities continue to invest does not indicate that the *rate of return* at which they invest is acceptable. The rate of return must be guided by the FRS, and not on the basis of a tipping point below which utilities would cease meeting their regulatory and contractual obligations.

36. Adding further context to the importance of a fair return was the OEB Chair's recent Statement, dated April 3, 2009:

> Ontario's electricity utilities are presently investing substantial amounts of capital to replace aging infrastructure, deploy smart meters, connect new load, and maintain system operability and reliability. In 2008, total capital expenditures by electricity transmission and distribution utilities totaled some $2.2 billion and expenditures in 2009

> are expected to total $2.6 billion. If passed, Bill 150, the *Green Energy and Green Economy Act, 2009*, will further increase utility infrastructure investment. Ontario's electricity utilities will be charged with planning for and connecting renewable distributed electricity generation. They will also be given responsibility to implement the smart grid and to take a lead role creating a conservation culture through the implementation of conservation and demand management programs….
>
> In my view this is an opportune time for the Board to ensure that the proper cost recovery approach is in place to encourage needed investment while protecting the interests of ratepayers.[2]

37. In the statement, the Chair has recognized the need to assure effective capital recovery so as to promote the availability of capital. Complementary to the notion that utilities should have adequate assurance for the return *of* capital is that utilities should have adequate assurance of a fair return *on* capital. The message from the Chair appears to give direction to ensure utilities are ready, willing, and able to support massive infrastructural growth in the Province; however, in order to attract the needed capital, especially from the non-government sector, returns must be comparable to those for investments of similar risk.

38. Currently, the whole of North America is occupied with updating antiquated electric and natural gas systems, and investing heavily in improvements and upgrades. Funds will necessarily flow to the enterprises that offer fair returns *on* and *of* capital. In the short run, Ontario's utilities will continue to invest, but the long run cost of sub-par returns could be much greater if investors begin to divert funds to other jurisdictions. The risk is that future returns would have to be set so high so as to divert funds back to Ontario, and investors would be sceptical of being treated fairly.

39. Evidence of the potential for this to happen was included in the American Gas Foundation's December 2008 paper, <u>Regulatory Policy of Return on Equity: Review and Analysis of the Natural Gas Utility Sector</u>, produced by Navigant Consulting, a copy of which is included as Item 4 in the accompanying Reference Materials CD.

[2] Ontario Energy Board, Statement from the Chair, <u>Re: Regulatory Framework for Approval of Investment in Infrastructure by Electricity Transmitters and Distributors</u>, April 3, 2009.

40. In that report, Navigant interviewed senior holding company executives, senior LDC executives, equity, and debt market analysts to provide an understanding of the ramifications of declining ROEs in the U.S. Navigant determined that, generally speaking, the market participants are concerned, particularly when the ROE level drops below 10%. According to Navigant:

> The overall summary of the analysts' and companies' assessments of the decline in allowed returns is that significant pressure is already being experienced in internally competitive investment choices, and that capital flight in public markets is a real possibility given changes in the investor population. Impacts are primarily seen in discretionary investment, in that the vast bulk of dollars invested by LDCs are required by the obligation to serve or by safety/integrity rules. As more than one senior executive put it, —As long as we are in this business, we will invest what it takes to run the business safely and reliably. However, we will not invest beyond what is necessary to do so, and we will increasingly look for ways to get out of the business if the observed declines in allowed returns are expected to continue.[3]

41. A fair return on investment must be allowed to achieve the Ministerial expectation for LDCs to lead the way in investing in Ontario's infrastructure. If the return on investment is perceived to be unfairly low, this will limit the ability and willingness of LDCs to provide such investment.

Question #3: What adjustments should be made to the Cost of Capital parameter values to compensate or correct for the current economic and financial conditions?

42. In order to compensate for the current economic and financial conditions, the Board should, as an interim measure, immediately adjust ROEs to provide returns that are reasonable on the basis of U.S. LDC benchmark returns and the recent TQM Decision (i.e., an increase of at least 200 to 300 basis points to the ROE, assuming that the equity thickness is held constant).

43. Before explaining the basis for this suggested level of adjustment, EGD believes that it is important to highlight that any short-term adjustment should be viewed as only an interim step. While the Company understands and appreciates that the

[3] Navigant Consulting, Regulatory Policy of Return on Equity: Review and Analysis of the Natural Gas Utility Sector, prepared for the American Gas Foundation, December 9, 2008, pp. 16-18.

Board is considering short-term adjustments to Cost of Capital parameter values, the Company respectfully submits that this should be followed by a more comprehensive proceeding. EGD's suggested next steps are detailed in response to the Board's fifth question.

44. To identify the appropriate level of adjustment to ROEs necessary in the short-term, the Company offers two rational methods that establish a fair rate of return for Ontario's utilities. These include the results of comparable U.S. LDC ROEs, as well as an examination of the decisions made by the NEB for TQM.

45. Work undertaken by Concentric and reported in Appendix 1, shows that allowed ROEs for electric and gas utilities in the U.S. are typically in the 10 to 11% range. It can be seen that there are few outliers earning below 9.5%. Typical equity ratios are in the 45 to 55% range (see Concentric's Figure 10 reproduced above). With there being no clear differences in risk between U.S. utilities and Ontario's utilities, to meet the comparable investment requirement of the FRS, Ontario's utilities should be allowed similar returns.

46. To derive an appropriately comparable return, it is important to compare on the basis of total return, just as the NEB did in the TQM Decision. The Brattle Group advises:

> The NEB found that an approach that determines a fair overall return has several advantages over formula-based methodologies that determine return on equity and equity thickness separately. Most significantly:
> (1) The NEB found that an approach that is directed at total return makes it easier to compare returns for companies of similar risk because it neutralizes differences due to financial risk.[4]
> (2) The NEB found that a total return approach is more transparent because it relies on a single number (the total return on capital) in making comparisons between companies of similar business risk. Thus, it does not require the regulator to make difficult evaluations of the capital structures specific to individual companies.[5]

[4] National Energy Board, RH-1-2008, p. 18.
[5] National Energy Board, RH-1-2008, p. 19.

(3) The NEB found that a total return approach is more consistent with the way companies make capital budgeting decisions.[6, 7]

47. Examining the returns provided for in the U.S. from this perspective, Ontario's utilities should be allowed returns that equate to 10 to 11% on 45 to 55% equity. Using the midpoints, 10.5% ROE on 50% equity yields a contribution to total return of 5.25%. For Ontario's electric LDCs, at a steady 40% equity ratio, the same contribution to total return would require an allowed ROE of 13.00%. For the gas utilities, at a steady 36% equity ratio, this would require an allowed ROE of 14.50%.

48. At a minimum, Ontario's utilities should be given the opportunity to earn the 200 to 300 basis point difference in allowed ROE; however, a return that meets the FRS requirement would also include the 10% difference in equity ratio (14% difference for gas utilities), indicating a 500 basis point spread from the currently calculated 8.01% ROE level.

49. Another way of viewing more appropriate returns for Ontario's utilities is by looking at the recent TQM Decision. In that decision, the NEB allowed TQM to earn 9.85% on 40% equity, or 185 basis points higher than the current ROE formula result in Ontario.[8] They also allowed TQM to make its own financing decisions, rather than adhering to a deemed capital structure, in applying the allowed total return on capital of 6.4%. At this total return on capital and an equity ratio of 36%, the allowed ROE for TQM equates to approximately 10.50%. Taken together, to be on par with the TQM Decision, Ontario's utilities would need an immediate lift in allowed ROEs of between 185 to 250 basis points.

50. The perspectives outlined above suggest that the ROE level for Ontario's utilities should be no lower than 10 to 11%, and could even be argued to be higher. At

[6] National Energy Board, RH-1-2008, p. 18.
[7] The Brattle Group, Report of Paul R. Carpenter, PHD for Enbridge Gas Distribution Inc., April 2009, pp. 9-10.
[8] BMO Capital Markets, Pipelines & Utilities, March 23, 2009. Note this calculation includes in the computation short term debt rates such that the total return equates to 6.4%.

these levels, the spread between the cost of equity and the cost of debt would return to a more normal 239 to 339 basis points.

51. The response above is necessarily simplistic in order to fit within the context and timing of this consultative process. It does, however, begin to address the gap between the current ROE level and that which satisfies the FRS. As set out further below, EGD believes that the Board should order a complete Cost of Capital review to assess the widening divergence between Ontario and comparable U.S. LDC ROEs, the changing interest rate environment, and the increased utility business risk environment, with the objective of establishing returns that meet the FRS.

Question #4: Going forward, should the Board change the timing of its Cost of Capital determination?

52. EGD believes that the timing for Cost of Capital determinations should facilitate the timing of utility rate applications. The timing should be consistent from year to year and, to the extent possible, should allow for the use of the most recently available data, while still permitting enough time for a utility to assemble its rate application.

Question #5: Are there any other key issues that should be considered if the Board were to adjust any or all of the Cost of Capital parameter values?

53. While the Company has provided support for ROE values it considers to be fair, this should not suggest that a simple, one time adjustment to the Cost of Capital parameter values will completely or adequately address the fundamental issues. The issue of how Cost of Capital should be set by the Ontario Energy Board in the future is a timely and imposing issue, and one that requires attention, for several reasons.

54. First, the current economic and financial conditions that prompted this proceeding have made it clear that the current approach to setting the Cost of Capital is producing unreasonable results that do not meet the FRS.

55. Second, while some observers may opine that past ROE reviews have failed to convince the Board that applicants really *need* a higher return than that established by the formula, the Company would respectfully submit that mounting evidence is now available that can provide the Board with more meaningful, and compelling reasons to think differently about the current approach to determining the Cost of Capital. For example, in addition to the reports and studies referenced earlier (the Major/Priddle paper and the Concentric study for the OEB), further studies commissioned by the CGA have also become available. One report, issued in April 2007, is titled Return on Equity: Allowed Returns for Canadian Gas Utilities. A second CGA report was issued in February 2008 and is titled Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis and was prepared by National Economic Research Associates, Inc. A third CGA report was issued in April 2008, and is titled, Natural Gas Utility Return Determination in Canada: Time for a New Approach. Copies of these reports are included as Items 5, 6 and 7 in the accompanying Reference Materials CD.

56. A third development is the willingness of Canadian regulators to consider whether a different Cost of Capital approach is appropriate. As already discussed, the NEB has considered the issue in the context of the TQM proceeding, and is now determining whether to hold a proceeding to address the NEB's ROE formula. The Alberta regulator is in the midst of a Generic Cost of Capital proceeding that encompasses all regulated utilities in that province. It is expected that other provincial regulators may also address the issue in the near future.

57. In all of these circumstances, EGD submits that the time is right for the Board to convene a separate, broader proceeding to comprehensively consider Cost of Capital issues for Ontario's regulated utilities, including the issue of what approach can be taken that will meet the FRS. Given the issues discussed in these submissions, including the need to create an attractive environment for investment

in Ontario's energy infrastructure, EGD believes that there is some urgency to getting such a proceeding underway.

58. From the Company's perspective, a generic hearing on Cost of Capital issues is preferred to a consultative process. A generic hearing would allow for a more complete exchange of facts and ideas, it would allow for direct presentation of the issues, and it would give the Board the opportunity to directly ask and have answered questions that emerge.

59. The Company believes one of two alternatives best suit the issue. The first alternative is to have the Board commence a separate proceeding to comprehensively consider Cost of Capital issues for all of Ontario's utilities. This alternative has the advantage of allowing a thorough examination and it provides the Board with some opportunity for economies of scale, that is, by reviewing the issue with respect to all of Ontario's utilities.

60. Another alternative is to have the Board commence two separate proceedings, one for Ontario's electric LDCs and one for gas LDCs. The main advantage of this alternative is that it would allow for industry specific examination of business risks and sample group comparisons.

61. While there might be some debate among stakeholders about how a change to EGD's ROE would apply during its incentive regulation term, EGD submits that this is an open question that need not be addressed until after the more fundamental Cost of Capital issues have been examined and determined.

The Cost of Capital in Current Economic and Financial Market Conditions

Prepared for:
Enbridge Gas Distribution

Comments in Response to Consultative Process
Board File No.: EB-2009-0084

April 17, 2009

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I. INTRODUCTION AND EXECUTIVE SUMMARY

Enbridge Gas Distribution here forth referred to as "Enbridge" retained Concentric Energy Advisors ("Concentric") to analyze and comment on the issues raised by the Ontario Energy Board ("OEB" or "Board") in its letter of March 16, 2009. The Board initiated a consultative process to determine whether current economic and financial market conditions warrant an adjustment to any of the Cost of Capital parameter values (i.e., the Return on Equity, Long-term Debt rate, and/or Short-term Debt rate) set out in the Board's letter of February 24, 2009.[1]

In addition to evaluating whether adjustments are warranted to the specified parameter values, the Board invited stakeholders to provide written comments on the issues listed below:

1. How do the current economic and financial conditions affect the variables (i.e., Government of Canada and Corporate bond yields, bankers' acceptance rate, etc.) used by the Board's Cost of Capital Methodology?
2. In the context of the current economic and financial conditions, are the values produced by the Board's Cost of Capital methodology and the relationships between them reasonable? Why, or why not?
   2.1. If the values are not reasonable, what are the implications, if any, to a distributor?
3. What adjustments, if any, should be made to the Cost of Capital parameter values to compensate or correct for the current economic and financial conditions?
4. Going forward, should the Board change the timing of its Cost of Capital determination, for instance, by advancing that determination to November? And,
5. Are there other key issues that should be considered if the Board were to adjust any or all of the Cost of Capital parameter values produced by the application of its established formulaic methodology?

In response, Concentric has prepared this paper to assist the Board with its deliberations on these important issues. Financial markets, regulators and utilities are clearly at a crossroads that requires a

[1] Ontario Energy Board, *Board Letter re.: The Cost of Capital in Current Economic and Financial Market Conditions, Board File No.: EB-2009-0084,* March 16, 2009.

fresh look at cost of capital. In addressing the specific questions posed by the Board, we feel it is important to establish a benchmark by which "reasonable" can be measured. In this regard, we turn to the tenets of the fairness standard, recognized as a central guiding principle by both Canadian and U.S. regulators. Application of the fairness standard to the cost of capital for Canadian utilities has been the subject of considerable writing and expert testimony in federal and provincial jurisdictions, so we draw upon that growing body of work in the following *Basis for Evaluating Reasonableness of Capital Costs* section.

In the *Regulatory and Economic Context* section, we detail the evolution of both Canadian and U.S. capital markets since the adoption of the Formula in 1996. This information shows the close integration of the Canadian and U.S. economies and the recent capital market conditions that have challenged even the most credit worthy companies to raise capital. Perhaps the most dramatic feature of this evolution is the tripling of credit spreads over government bond yields for A-rated companies in both Canada and the U.S. Against this backdrop, Ontario's gas and electric utilities must raise capital for ongoing operations and to meet provincial goals for energy efficiency, system upgrades, and renewable energy interconnection. The ability to raise capital on reasonable terms has significant impacts on utilities and their customers. Current financial markets have challenged the cost of capital Formula to keep pace with actual market conditions, but this has only exacerbated a structural problem from day one: financial markets and the cost of capital prescribed by the Formula in Ontario do not move in harmony.

In the *Issues with the Existing ROE Formula* section, we provide data illustrating the mismatches between the Ontario cost of capital estimates and comparative measures. This gap is most prominent in the case of ROE. We compare the cost of equity from the current Ontario Formula with benchmarks from recent decisions in Canada and the U.S. that provide context. A growing chorus of equity analysts, industry experts and the NEB have concluded that ROE formulae employed in Canada no longer appropriately reflect the real world cost of capital. The primary cause for this divergence is the relationship to Long Canada bonds which has not reflected measures of corporate capital costs. The NEB's TQM decision has formalized the mounting evidence that suggests a new approach is required. While we have not formally estimated an ROE for Ontario's utilities, the Formula ROE for 2009 may understate actual cost of equity by as much as 300 basis points.

In the *Reasonableness of Short-term and Long-term Debt Rates* section, we find that the deemed long-term debt rate appears to be performing more reasonably, as it is tied to actual credit spreads for investment grade utilities, and not limited to Long Canadas, which is a fundamental problem with the ROE determination. The Board's short-term debt determinant remained at a fixed spread over bankers' acceptances while actual borrowing costs have pressed upwards as a direct result of the credit squeeze in current markets. The debt rates may be recalibrated, but we are less sanguine that the existing ROE Formula can be recalibrated and remain an accurate indicator of actual equity costs.

In our *Conclusions*, we find that current economic and financial market circumstances have had a material impact on the variables used by the Board in its cost of capital methodology. The banker's acceptance rate is a reasonable underlying indicator of short-term utility debt costs, but while that rate has fallen over the past 6 months, credit spreads have widened considerably. The current 25 basis point differential requires recalibration to remedy this problem. Long-term debt rates and access to debt markets have also been materially impacted by the current environment, but the reliance on investment grade utility spreads over Long Canadas does a reasonable job of tracking actual market conditions. The greatest gap between estimated and actual capital costs lies in ROE. As yields on Long Canadas have been driven lower, all apparent indicators of equity costs have pointed in the opposite direction, exaggerating a trend which began with the steady decline on government bond yields. We ultimately conclude that capital cost values arising from the Board's existing approach, with particular focus on the ROE and short-term debt rate, would not meet an objective test of fairness. It may be possible to temporarily recalibrate the cost of equity with a transitional "adder" for 2009, but a sustainable solution requires a full evaluation of the cost of capital accounting for both current and anticipated market conditions.

II. BASIS FOR EVALUATING REASONABLENESS OF CAPITAL COSTS

The basis for evaluating whether capital costs produced by the Formula are reasonable is ultimately a question of satisfying the fairness standard. "Fair" has been defined through a series of bellwether decisions that are widely recognized in the regulatory community. In the U.S., *Bluefield Waterworks and Improvement Company v. Public Service Commission of West Virginia (1923) ("Bluefield")*, and *Federal Power Commission v. Hope Natural Gas Company (1944) ("Hope")* established these important foundations. In Canada, the Supreme Court in *Northwestern Utilities v. City of Edmonton (1929) ("Northwestern")* established a comparable foundation for utility cost of capital. As stated by Mr. Justice Lamont in that case:

> *The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise….* [2]

The NEB has further summarized its view that the fair return standard can be met by fulfilling three particular requirements. Specifically, a fair or reasonable return on capital should:

- Be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment requirement);
- Enable the financial integrity of the regulated enterprise to be maintained (the financial integrity requirement); and
- Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction requirement).[3]

In this paper, Concentric examines the results of the generic rate of return Formula for Ontario's utilities and its ability to meet these standards given current economic conditions.

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2 Northwestern Utilities v. City of Edmonton [1929] S.C.R. 186 (NUL 1929).

3 Reasons for Decision, TransCanada Pipelines Limited, RH-2-2004, Phase II, April 2005, Cost of Capital, and reaffirmed by Reasons for Decision, Trans Quebec & Maritimes Pipelines, Inc., RH-1-2008, March 2009, at 6-7.

Concentric's research for this report is supported by several recent studies and reports, developed by Concentric and others, which have evaluated the returns produced by the Formula. These studies include:

- *Return on Equity: Allowed Returns for Canadian Gas Utilities*, A Discussion Paper Developed by the Canadian Gas Association, May 2007;
- *A Comparative Analysis of Return on Equity of Natural Gas Utilities*, prepared for the Ontario Energy Board by Concentric Energy Advisors, June 14, 2007;
- *Perspective on Canadian Gas Pipeline ROEs*, Canadian Energy Pipeline Association, February 2008;
- *Allowed Return on Equity in Canada and the United States*, National Economic Research Associates, February 2008 (study commissioned by the Canadian Gas Association);
- *The Fair Return Standard for Return on Investment by Canadian Gas Utilities*: Meaning, Application, Results, Implications, The Honourable John C. Major Former Justice, Supreme Court of Canada and Roland Priddle, President, Roland Priddle Energy Consulting Inc. and Former Chair of the National Energy Board, March 2008; and
- *A Comparative Analysis of Return on Equity for Electric Utilities*, prepared for the Coalition of Large Distributors ("CLD")[4] and Hydro One Networks Inc. by Concentric Energy Advisors, June 2008.

In addition, witnesses for Concentric have recently presented substantial evidence on this topic before the Alberta Utilities Commission in its Generic Cost of Capital proceeding (Proceeding ID.85).

4 The members of the CLD include: Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, Powerstream Inc., Toronto Hydro-Electric Systems Limited and Veridian Connections Inc.

III. REGULATORY AND ECONOMIC CONTEXT

HISTORICAL PERSPECTIVE ON THE ONTARIO COST OF CAPITAL

The adoption of a formulaic approach to setting regulated authorized equity returns in Canada was first established by the BC Commission in 1994. Subsequently, other regulatory bodies in Canada followed suit. In Ontario, the ROE Formula was first implemented for natural gas distribution utilities in 1997, with the OEB's Draft Guidelines on "A Formula-Based Return on Common Equity for Regulated Utilities". Up until 1999, Ontario's electric distributors were principally municipal utilities under the regulation of Ontario Hydro and earned no specified rate of return on equity. Not until 1998 and the passage of the *Energy Competition Act* ("the Act"), did the OEB have the authority to fix "just and reasonable" rates for Ontario's 270 plus municipal electric utilities that existed at that time. Based on methodological recommendations forwarded by Dr. William Cannon, a desire to align with existing methods for gas distributors, and the objective of implementing a performance based ratemaking framework, the Board also established a formulaic risk premium approach to ROE for electric distribution utilities.[5]

OVERVIEW OF CURRENT ECONOMIC CONDITIONS IN THE U.S. AND CANADA

Like the U.S. economy, the Canadian economy has entered a recession. Initially, this contraction was attributed to the close link between the two economies, but it has been exacerbated by the precipitous decline in natural resource prices, the drop in Canadian exports, and declining domestic demand for goods and services since the beginning of 2008. In Concentric's studies prepared for the OEB and for Hydro One and the CLD, referenced earlier in this document, significant evidence was presented to demonstrate that the U.S. and Canadian economies are closely integrated. In the Hydro One CLD study, Concentric analyzed such macroeconomic factors as GDP growth, broader market indices, CPI, and exchange rates for the two countries and concluded that the economies are closely integrated. We noted in 2006, Canada exported nearly 82% of its total exports to the U.S. and imported from the U.S. roughly 55%. Based on our examination of the business and regulatory environment for utilities in the U.S. and Canada, we have not found dissimilarities that would

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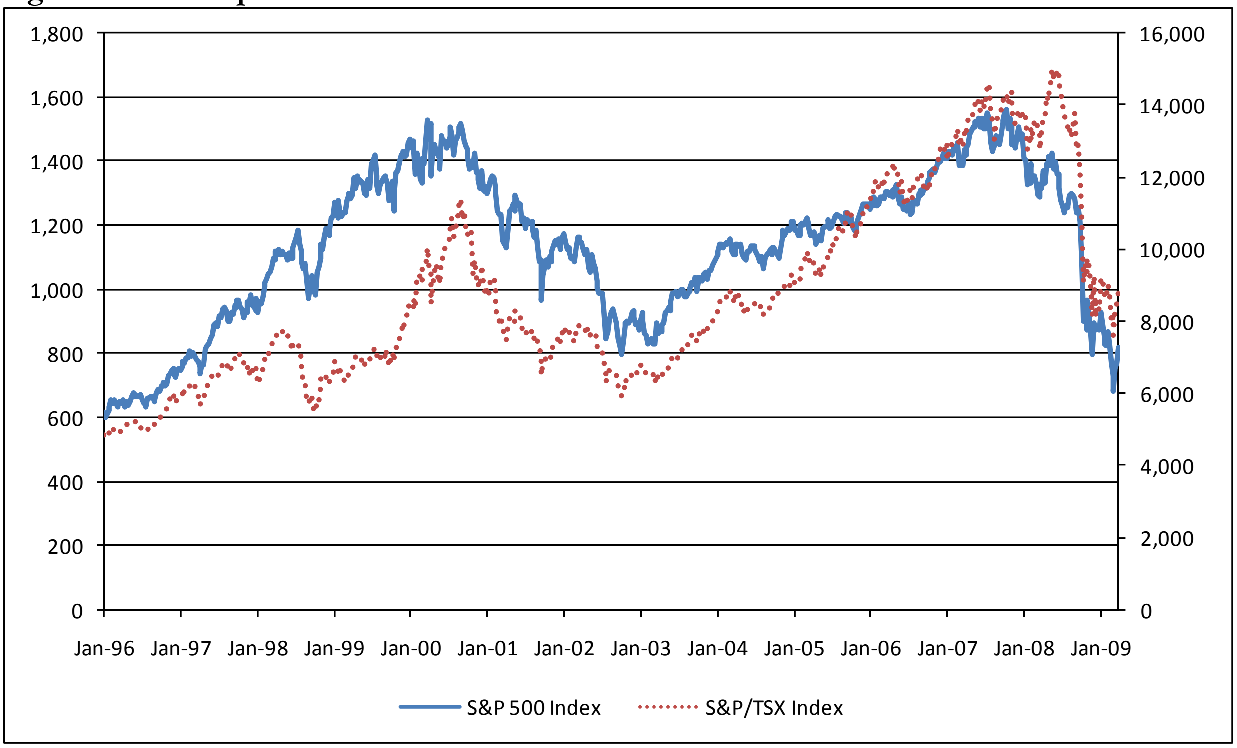
[5] See*: A Discussion Paper on the Determination of Return on Equity and Return on Rate Base for Electric Distribution Utilities in Ontario*, Dr. William T. Cannon, December, 1998; and *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electric Distributors*, Ontario Energy Board, December 20, 2006.

explain a significant difference in investors' expectations nor anything to suggest that Ontario utilities should receive lower returns than those in the U.S.[6]

Figure 1 compares the U.S. and Canadian stock market indices through March 2009, showing the strong positive relationship between the two indices. The correlation coefficient for the two markets is 0.753 for the entire period; and over the past five years (April 2004 – March 2009), that relationship has increased as evidenced by the correlation coefficient of 0.852.

Figure 1: A Comparison of Broader U.S. and Canadian Market Indices



Source: Bloomberg

Similarly, the S&P 500 and the S&P/TSX Utilities indices show the same strong relationship. As indicated in Figure 2, since January 1996, the utilities indices were positively correlated by a factor of 0.489, but since 2004 that relationship has strengthened and the two indices are now positively correlated by a factor of 0.930. This convergence of U.S. and Canadian utilities indices in the early

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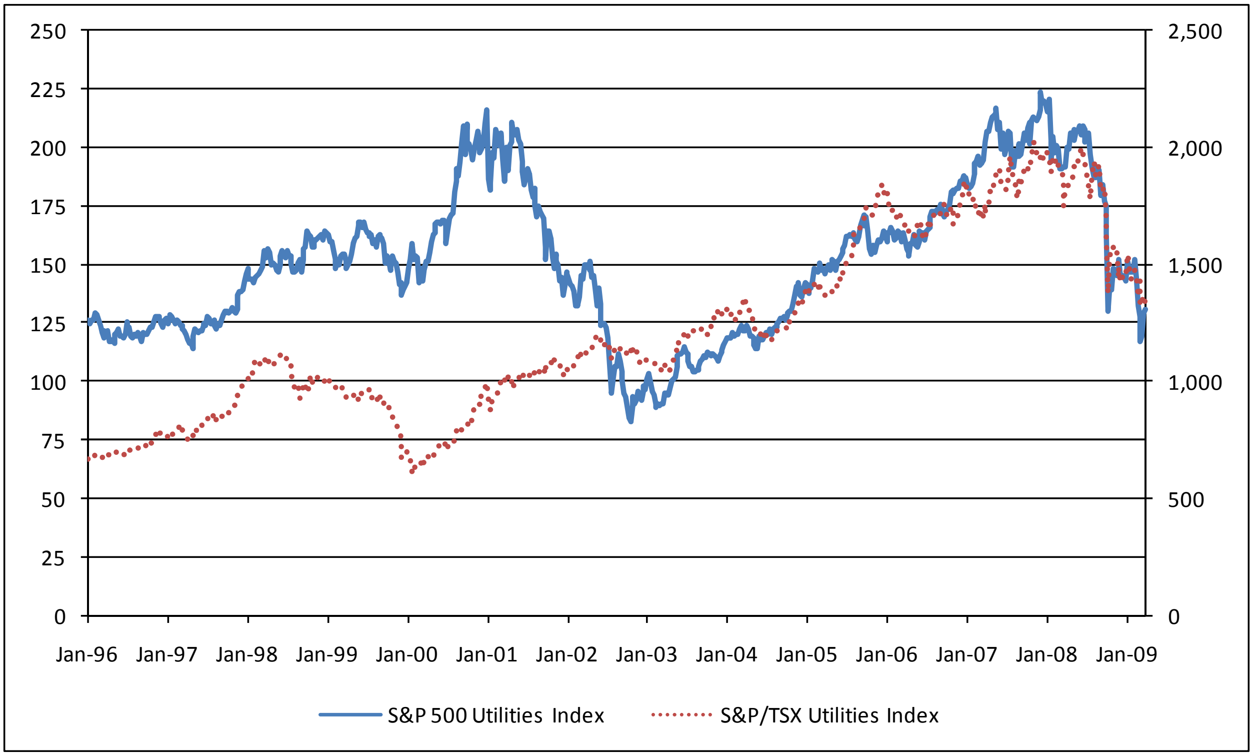
6 Concentric Energy Advisors, *A Comparative Analysis of Return on Equity of Natural Gas Utilities*, Prepared for the Ontario Energy Board, June 14, 2007, at 57-58; and, Concentric Energy Advisors, *A Comparative Analysis of Return on Equity For Electric Utilities FINAL REPORT*, Prepared for The Coalition of Large Distributors and Hydro One Networks Inc., June 2008, at 42-43.

2000's, specifically 2000 and 2001, is plausibly explained by the increased integration of the two economies, as well as the shedding of risky assets by regulated utilities in the aftermath of the California energy crisis and the Enron bankruptcy.

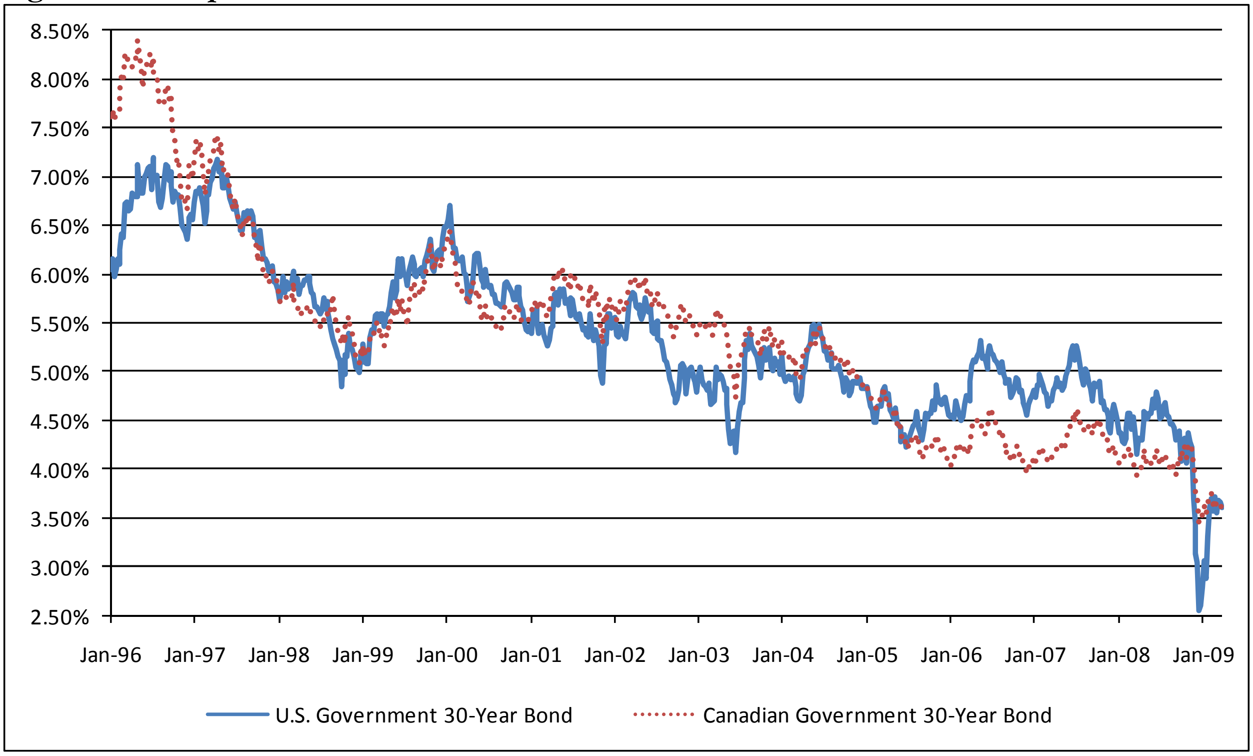
Figure 2: Comparison of U.S. and Canadian Utility Indices



Source: Bloomberg

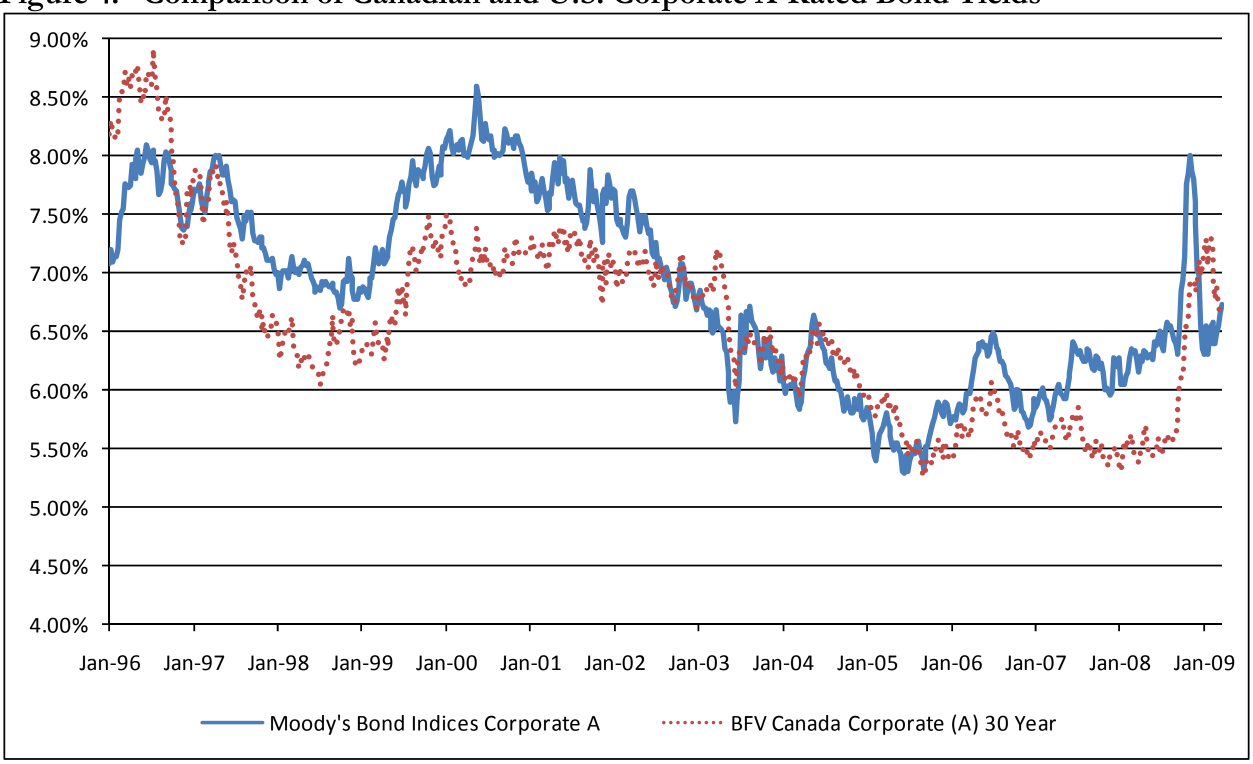
A review of government and corporate bond yields also provides evidence of the integration between the two economies. Figures 3 and 4 contain comparisons of U.S. and Canadian government and corporate bond yields. Clearly, the economies, and more importantly for the OEB's questions, financial markets, are moving in near lock step.

Figure 3: Comparison of U.S. and Canadian 30-Year Government Bond Yields



Source: Bloomberg

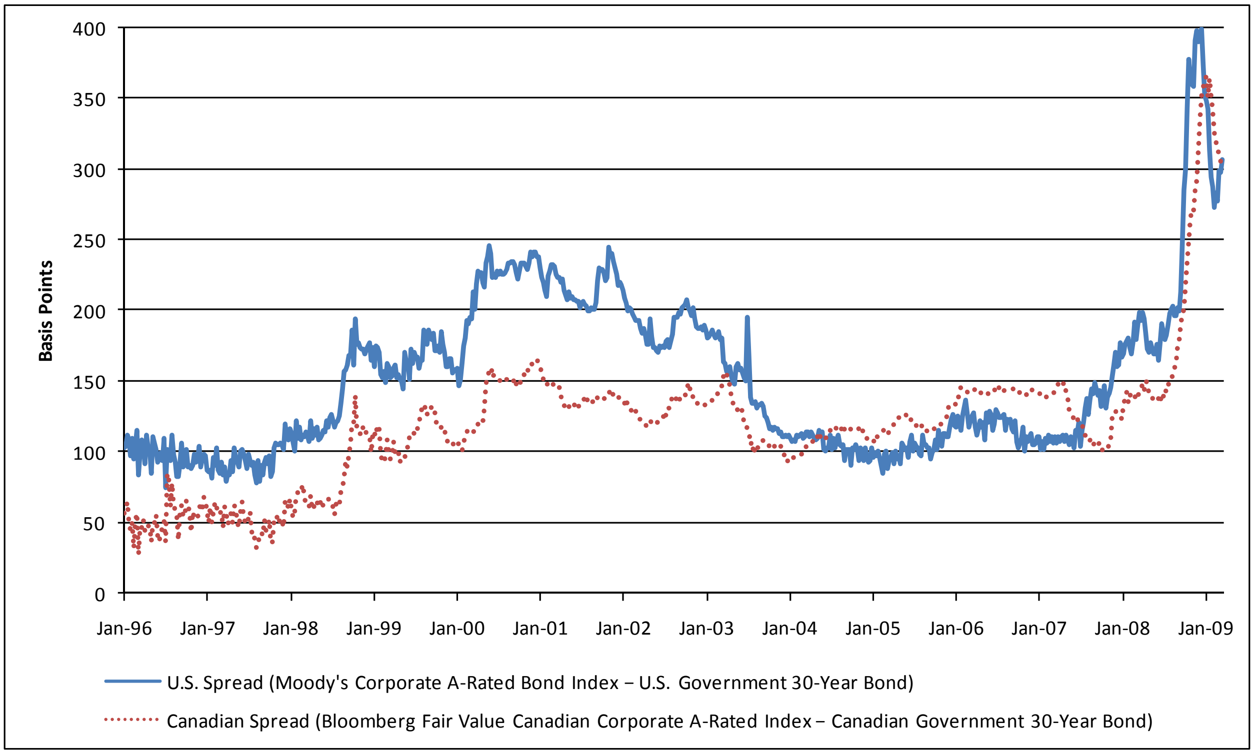
Figure 4: Comparison of Canadian and U.S. Corporate A-Rated Bond Yields



Source: Bloomberg

What is evident from the above charts is: (1) the U.S. and Canadian economies and utility sectors move in close correlation; and (2) both economies have experienced a significant decline as a result of the current recession. Further, as illustrated by a comparison of credit spreads in Figure 5, capital costs are rising sharply even though government bond yields are falling.

Figure 5: A Comparison of U.S. and Canadian Corporate Credit Spreads Over the 30-Year Government Bond Yields



Source: Bloomberg

As illustrated above, corporate credit spreads have spiked in recent months as have corporate borrowing costs to compensate investors for the increased risk, unprecedented in recent history, in financial markets. In 2008, the U.S. total market lost 38.3% of its value and Canada experienced an even greater loss of 45.7%. This financial crisis has caused a crisis of investor confidence that will have a lasting effect on the price of risk.

The current financial crisis has several implications for utilities: 1) widening credit spreads for debt issuances; 2) reluctance to issue common equity amid weak markets; and 3) reduced or deferred capital spending plans for necessary infrastructure. These issues are captured by a special comment published by Moody's Investor Services on October 13, 2008:

> *Although longer-term relief may not be completely out of the question, many utilities are reluctant to incur the risk of sizeable deferrals on their financial statements. These infrastructure investments have been identified as necessary, given the age of the assets, and continued regulatory support has been incorporated into most utilities' long-range forecasts, including an expectation that returns on capital would be reasonable. Should this prove not to be the case, it could represent the first crack in our fundamental assumption regarding the sector's ratings and ratings outlook.*[7]

Although utilities continue to have access to credit markets, borrowing costs and credit spreads have increased significantly, regardless of the credit worthiness of the debt issuer. According to Scotia Capital, "Deleveraging and general risk aversion has sent even the highest-grade credit spreads to record highs." The bank further offers the "Market remains mostly shut to non-Government backed issuances in Canada post Lehman."[8]

Some thawing of credit markets has occurred over the past few weeks, but credit-worthy borrowers are paying a substantial premium over the risk free rate for debt capital. Because utilities are capital intensive businesses which are highly leveraged, especially in Canada, the availability of reasonably priced debt financing is critical to their financial integrity. These issues are particularly important for the Ontario utilities, which have elevated capital expenditure projections because of the planned replacement and expansion of infrastructure in the Province.

ONTARIO INVESTMENT INITIATIVES AND CAPITAL REQUIREMENTS

Ontario is deploying an aggressive campaign to update its electric distribution grid and pursue green generation technologies. These initiatives are incremental to the steady customer growth in Ontario's major metropolitan areas and the maintenance requirements associated with safely operating some of the Country's oldest electric and natural gas distribution infrastructures in accordance with increasingly stringent technical and environmental standards. Additionally, Ontario utilities will be called upon to develop assets to promote and facilitate an optimal allocation of energy resources, such as developing natural gas storage capacity or developing infrastructure to

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7 "Moody's: Investor-owned Utilities somewhat insulated from economic instability," SNL Financial, October 14, 2008, Rosy Lum.

8 Scotia Capital, Fixed Income Research, 2008 in Review, Jan., 2009, at 8 and 15.

accommodate new and environmentally sound sources of power generation. Many of these strategic initiatives are laid out in specific plans that have identified a substantial amount of investment capital that will be required in the next several years.

First, Ontario's Integrated Power System Plan ("IPSP") estimates roughly $16 billion[9] (in 2007 $'s) to be spent over the next five years on electrical distribution alone, exclusive of the costs of new generation, conservation, and transmission. In addition, the Government of Ontario is in the midst of a smart metering initiative that established targets for the installation of 800,000 smart electricity meters by December 31, 2007 and for all Ontario customers by December 31, 2010. The cost of this initiative was estimated to be approximately $1 billion.[10] The Smart Grid initiative of June 2008 addressed the challenges of incorporating distributed generation, accommodating growth, and replacing aging infrastructure while maintaining reliability and quality of service by adding wires with intelligence to the grid at an incremental estimated cost of $320 million over the next five years.[11] Lastly, the Green Energy Act, which aggressively pursues renewable energy targets, is incremental to the directives mentioned above and will substantially increase the capital requirements in Ontario to connect new renewable energy resources to the grid.

This is a time of unprecedented capital growth in Ontario to meet the Government's energy and infrastructure objectives. These objectives can only be met if there is adequate cash flow to finance debt and encourage new equity infusion to maintain capital ratios. These enormous capital requirements come at a time when the costs of capital and credit spreads have ballooned to levels unprecedented in the recent past, while the Ontario ROE Formula prescribes the lowest equity return authorized by the OEB in the history of Ontario's utilities,[12] 8.01 percent, barely over the current long-term debt cost. Low rates of equity return do not encourage investment and in fact may undermine some of the investments already undertaken. Many of the technologies being proposed for Green Energy are new and untried and the size of these initiatives dwarf most comparable initiatives in the U.S., dispelling any notion that Ontario utilities are lower risk than their

9 Ontario IPSP, EB-2007-0707, Exhibit G, Tab 2, Schedule 1, Page 27 of 32, Table 20, Corrected: October 19, 2007

10 The Ontario Electricity Distributors Association, *Ontario's Electricity Distributors and the Government's Smart Meter Initiative*, http://www.eda-on.ca

11 *Enabling Tomorrow's Electricity System Report of the Ontario Smart Grid Forum*, at 14.

12 According to records dating back as far as 1985.

U.S. counterparts. At a credit spread of 39 basis points over corporate borrowing costs, the formulaic ROE result is not credible and is significantly out of touch with the realities of Ontario's current business environment and the global economic environment where investment grade credit spreads have increased on the order of 300 – 500 basis points. Regulators must consider how to satisfy this elevated need for capital in the current economic climate. It has become increasingly evident that the fundamentals underlying the ROE Formula have changed and the Formula is no longer producing realistic results.

IV. ISSUES WITH THE EXISTING ROE FORMULA

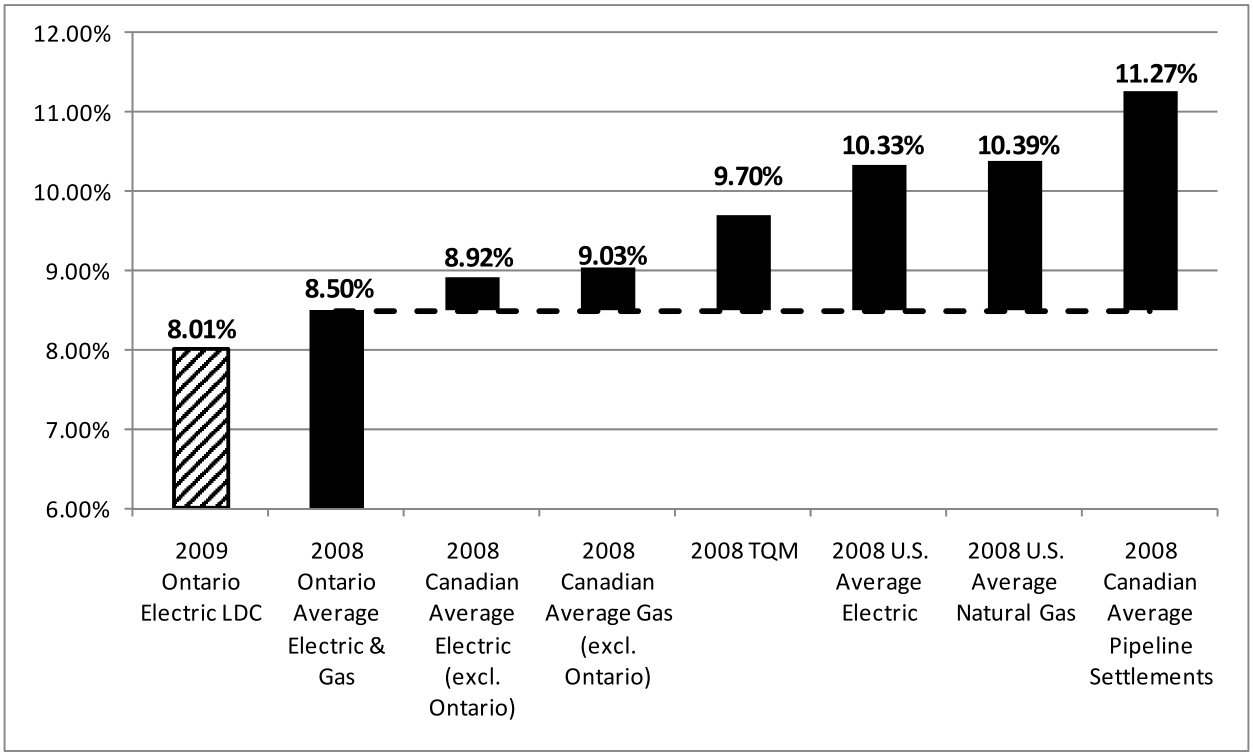
BACKGROUND

Prior to the implementation of the formulaic ROE approach, adopted by the OEB for its natural gas utilities in 1997, ROEs in Canada and the U.S. were in virtual parity.[13] Since the adoption of the formulaic approach for Ontario's gas utilities in the "Draft Guidelines on a Formula-Based Return on Common Equity", a growing gap between the returns of U.S. gas utilities and Canadian gas utilities has developed. That divergence extends to the 80 plus electricity distribution utilities currently operating in Ontario, who have since been regulated under the same formulaic approach. Figure 6 illustrates the Formula ROE in effect for 2008, and proposed for 2009, against other measures of equity costs. Ranging from the recent TQM Decision to recent Canadian pipeline settlements for additional context, the Ontario ROE would be lower by 146-218 basis points. Concentric's analysis reveals for 2009, that there is presently an approximate 279 basis point difference between allowed natural gas and electric distribution utility ROEs in the U.S. versus Ontario. These differences are exacerbated by the lesser equity thicknesses of the Ontario utilities, which on average employ 10-15 percent less equity in their capital structures than in the U.S., further widening the gap between U.S. and Ontario authorized returns. Given the growing disparity between government bond yields and actual corporate capital costs, we would expect this ROE gap, left unchecked, to continue to grow as high as 300 basis points.[14]

13 Concentric Energy Advisors, Inc., *A Comparative Analysis of Return on Equity of Natural Gas Utilities*, June 2007, at 13.

14 Recent U.S. ROE awards for March and April 2009, range from 10.17 on the low end to 11.50 on the high end, with an average ROE of 10.74%, on 48 percent equity. A calculation of the Ontario ROE, based on the most recent (March 2009) Consensus Forecast, yields an ROE of 7.95%, currently resulting in a difference of 279 basis points from the average U.S. return.

Figure 6: Relevant Benchmarks for Ontario Authorized ROE



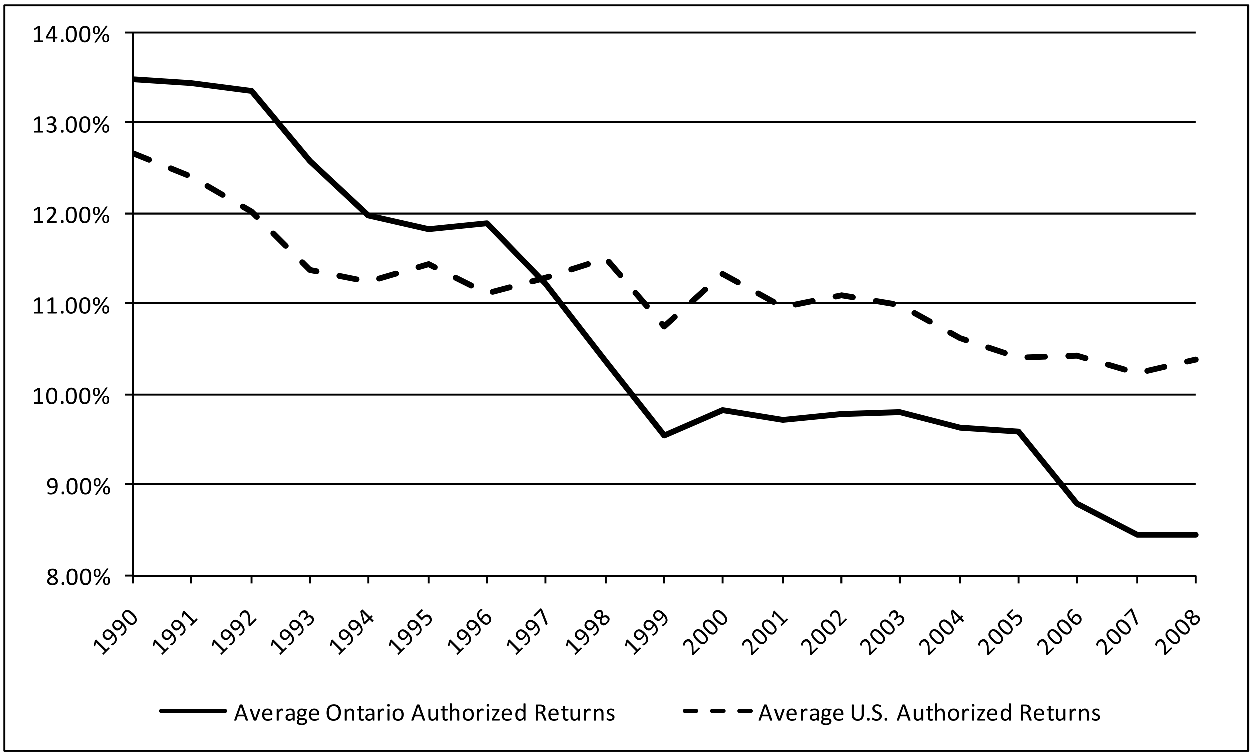
Sources: SNL RRA Database for U.S. authorized returns for 2008 (Gas and Electric LDCs); Ontario 2008 authorized returns produced by the Formula (average of electric LDCs 8.57%, Enbridge Gas Distribution 8.39%, Union Gas Ltd. 8.54%); Canadian average (excl. Ontario) per Annual Reports and Rate Applications. Canadian 2008 Negotiated Pipeline Settlements authorized returns (average of Maritimes & Northeast 11.66%, Alliance Pipeline 11.26%, Alberta Clipper 10.96%, Line 4 Extension 10.96%, Trans Mountain Pipe Line 10.75%, Southern Lights 12.00%), and TQM return for 2007-2008 as set by the NEB (assuming 40% equity).

Although current economic conditions provide visibility into the shortcomings of the Formula, they should not be construed as the cause of the problem. It is Concentric's view that an approach relying entirely on a single input, subject to cyclical market fluctuations, is exposed to a high risk of error. Without performing objective corroborating analyses there is insufficient information to determine whether a given formula is arriving at results that are reasonable. A formula that depends solely on changes in the government bond yield is problematic, particularly in the current market environment, and warrants a thorough review by the OEB and stakeholders.

EVIDENCE OF PROBLEMS WITH THE FORMULA

The gradual decline in government bond yields and the sensitivity to interest rates, fundamental to the Ontario ROE Formula, have resulted in a deep and expanding gap between the equity returns of the U.S. and Canadian utilities. Figure 7 (below) illuminates the disparity between U.S. and Canadian returns that existed through 2008. As mentioned, the current economic woes have deepened the divide as the difference in utility ROEs between the U.S. and Ontario approach 300 basis points.

Figure 7: The Growing Gap between Ontario and U.S. Natural Gas Utility ROEs



Source: SNL Database for U.S. Natural Gas LDCs; Ontario Gas LDC data obtained from Concentric Comparative Analysis of Return on Equity of Natural Gas Utilities updated through 2008 Annual Reports

As shown previously in Figure 3, Canadian bond yields have steadily declined since 1997 and as the Figure above shows, this has led to a steady decline in the return on equity calculated by the Formula. This decline has been exacerbated by the current economic crisis, whereby government bond yields have dropped as the central bank attempts to stimulate economic activity by keeping borrowing rates low and investors flock to low-risk investments, further driving down the yields on government bonds. The Ontario ROE Formula is directly linked to changes in government bond yields, whereby an elasticity factor (or sensitivity) of 0.75 has been established for equity returns vis-à-vis government bond yields; i.e. for a given change in interest rates, Ontario's authorized ROEs will adjust by a factor of 0.75. Additionally, the equity risk premium implied by the Formula moves inversely to interest rates by a factor of 0.25 or (1 – 0.75).

To assess the reasonableness of the elasticity factor of 0.75 in the Ontario Formula, we have performed a regression using U.S. utility authorized return data as the dependent variable to quantify this historical relationship. We have selected U.S. LDC utility returns as they provide a robust data sample, outside of the Canadian market dominated by the Formula, and we consider them to be a close proxy to Canadian utility returns. This regression describes the relationship of newly authorized returns for regulated utilities as a function of the quarterly prevailing long-term government bond yields (β_1). Because of the recent anomalous behavior of government bond yields to corporate bond yields associated with the current economic crisis, we have isolated the period from the 4th quarter of 2008 to the present in two ways: first by eliminating the period altogether; and second by using a dummy variable to isolate the period (β_2).

Table 1: Elasticity Factor Regression Results

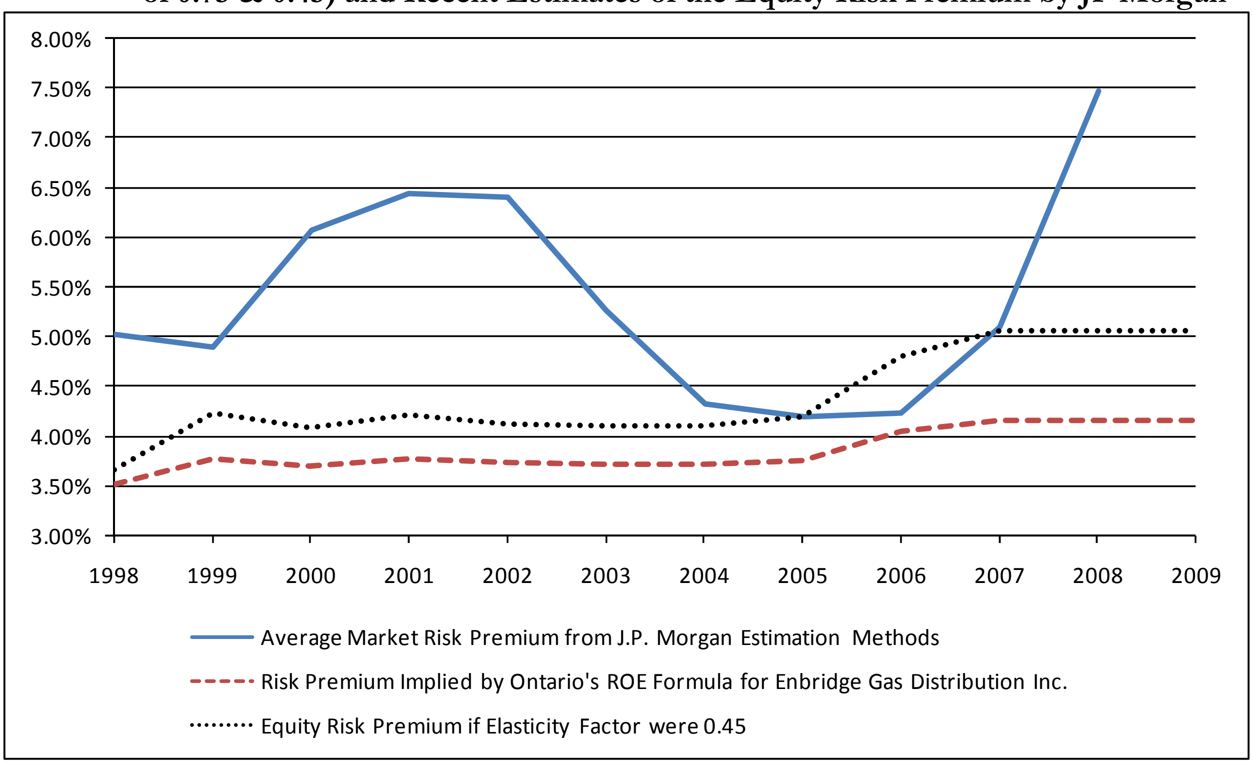
	Intercept	t-stat$_\alpha$	β_1	t-stat$_1$	β_2	t-stat$_2$	R^2
Authorized Return Regression Model = Intercept + (X * bond yield) = Authorized Return							
US LDCs (1989 – Q3 2008)	0.0855	33.385	0.446	10.809			0.6070
US LDCs (1989 – Q1 2009)	0.0868	36.634	0.426	11.034			0.6160
US LDCs (1989 – 2009 with) Dummy for (Q4 08 – Q1 09)	0.0855	33.637	0.445	10.859	0.467	1.349	0.6150

Although the above regression results do not address the current disassociation of government bonds and corporate capital costs, they do indicate, consistent with those we have estimated previously,[15] that the typical elasticity factor of U.S. authorized returns to government bond yields has historically been approximately 0.45, versus the 0.75 elasticity factor set out in the Formula. This implies that the risk premium should have actually increased by approximately 0.55 for each percentage point drop in the government bond yield (as opposed to the 0.25 implied by the Formula). This misspecification of the elasticity factor has resulted in the systematic understatement of utility ROEs and equity risk premiums over the past decade. However, as illustrated below, correcting for that misspecification, based on historical data, would not provide an ROE result that is either sufficiently responsive to existing economic conditions or "fair".

[15] Concentric performed similar regression analyses in each of the studies prepared for the OEB in 2007, and for Hydro One and the CLD in 2008, referenced earlier in this document.

In Figure 8, Concentric has charted the equity risk premiums implied by the current Formula and that which would have been implied had the original elasticity factor of the Formula been set at 0.45 rather than 0.75. As the Figure shows, this difference alone could lead to differences in authorized returns over the period of nearly 100 basis points. We have then compared these implied risk premiums to the forward-looking market risk premium estimates provided by JP Morgan. In that analysis, JP Morgan provided their estimates of the market risk premium under various methodologies. We have averaged those annual estimates to compare with those produced by the actual and the hypothetical formulae. As the Figure below illustrates, the formulae, under either scenario, are not adequately responsive to the marked increase in equity risk premiums over the past two years.

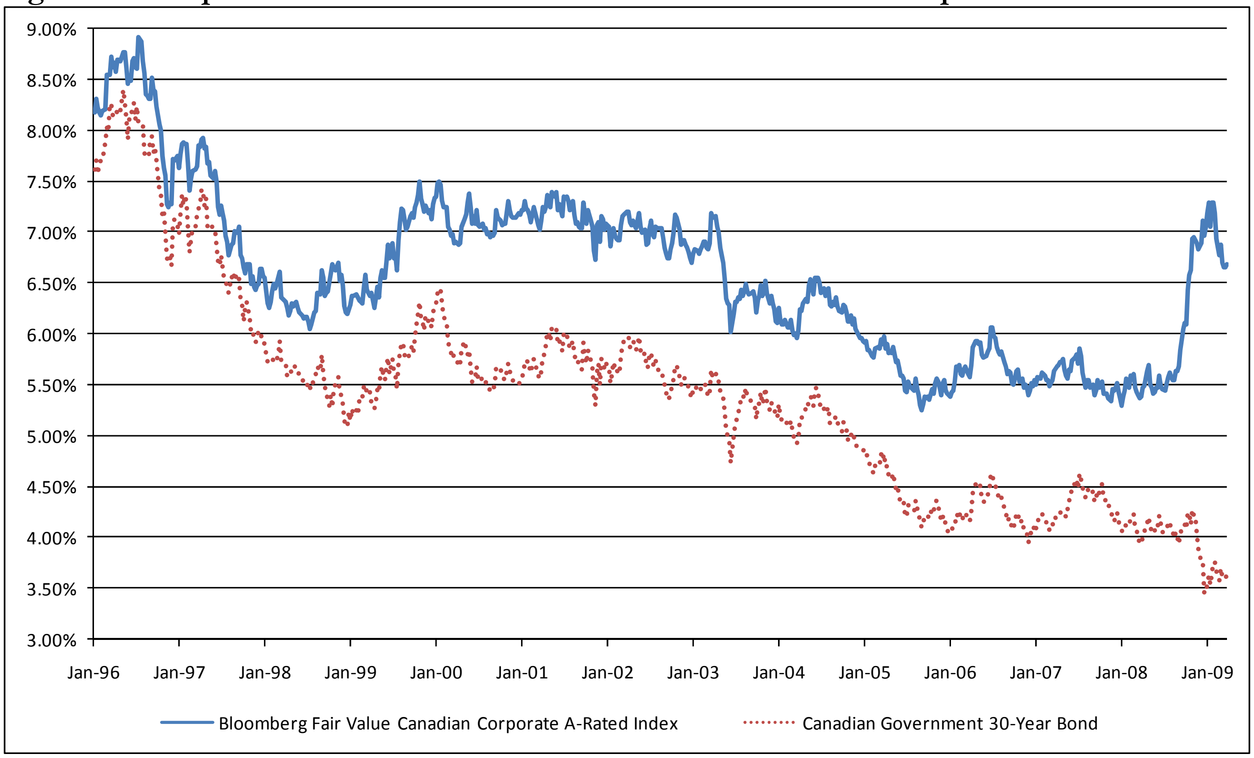
Figure 8: Comparison of Risk Premiums Implied by the Formula (using Elasticity Factors of 0.75 & 0.45) and Recent Estimates of the Equity Risk Premium by JP Morgan



Source: Risk Premiums implied by the current Formula and that implied assuming a elasticity of 0.45, were calculated by Concentric. The JP Morgan estimate is the average of three separate methodologies (Dividend Discount Model (DDM), Constant Sharpe ratio, and Bond-market implied risk premium) published in JP Morgan's November 2008 Presentation: The Most Important Number in Finance – The Market Risk Premium".

Like equity risk premiums discussed above, corporate borrowing costs and credit spreads, as shown previously, in Figure 5 have spiked. The Figure below precisely illustrates another fundamental flaw in the existing Formula.

Figure 9: Comparison of Canadian Government Bond Yields and Corporate Bond Yields



Source: Bloomberg

As corporate borrowing costs and credit spreads are rising and the risk of equity ownership is increasing, government bond yields are declining, which results in changes to ROEs produced by the Formula which are directionally incorrect. There is no logical justification for decreasing equity returns in the midst of rising capital costs. An equity holder would happily sacrifice the 39 basis point equity risk premium over corporate bond yields, suggested by the Formula, to secure a fixed and more certain return. Even though historically there has been a strong positive relationship between government and corporate bond yields, prevailing influences on each debt instrument, such as monetary policy on one hand and risk of default on the other, have caused the strong positive relationship to de-link and actually move in opposite directions. A temporary fix to the Formula does not address this inherent weakness. In the event that credit spreads migrate back to historical tolerances, the deficiencies in the Formula may be obscured but will not be resolved. It is for this reason that any formulaic approach to setting a return for equity holders must be accompanied by a process of corroborating the results for reasonableness relative to other benchmarks.

THE RELEVANCE OF THE TQM DECISION

It is worthy to note that the NEB has visited the issue of the broadly adopted Canadian ROE Formula in its March 2009 Decision on the TQM cost of equity. After months of deliberation and extensive expert testimony, the Board found several reasons to doubt the applicability of the Formula given the "new business environment" and all the changes that have occurred since its original adoption in 1994.

The NEB Decision broke new ground in reconsideration of the Formula. The Board cited several factors that led to its ultimate Decision. Interestingly, the current economic environment was notably absent as a factor in their Decision. However, the Board did state that it was of the view that there have been significant changes in financial markets as well as in general economic conditions since the Formula's inception in 1994; specifically, Canadian financial markets have experienced greater globalization. The Board acknowledged that the increased globalization of financial markets translates to a higher degree of competition for capital among North American utilities. Secondly, the Board noted that the decline in the ratio of Canadian government debt to GDP has put downward pressure on Canadian bond yields. The Board acknowledged that government bond yields do not capture all of the changes that could impact TQM's cost of capital and specifically stated:

> *The RH-2-94 Formula relies on a single variable… the long Canada bond yield. In the Boards' view, changes that could potentially affect TQM's cost of capital may not be captured by long Canada bond yields, and hence, may not be accounted for by the results of the RH-2-94 Formula. Further, changes regarding (TQM's) business environment… may not have been captured by the Formula. Over time, these omissions have the potential to grow and raise further doubts as to the applicability of the formula result for TQM for 2007 and 2008.*

The TQM Decision adopted an ATWACC approach, recognizing that equity returns and capital structure are intertwined and should be considered together in estimating a utility's cost of capital. This Decision provided an approximate 170 basis point differential in relation to the most recent Ontario ROE of 8.01 percent, and confers greater flexibility to utility management to adopt its own capital structure based upon its assessment of appropriate leverage under existing conditions.

The Board's Decision validated increasingly vocal criticisms of the Formula. Many equity analysts have stated that Canadian ROE formulas are broken, claiming that these formulas are no longer representative of current market conditions. Stephen Dafoe with Scotia Capital opined on the single most important factor in the NEB's recent decision regarding TQM's cost of capital:

> *In our view, the single largest factor in the NEB's TQM Decision was the gradual decline in Canada yields from 1995 to 2007. However, in addition to this long and gradual decline, since the failure of Lehman Bros. in September, 2008, global sovereign yields have plunged precipitously, while credit spreads, and the cost of equity, have ballooned. Clearly, this mismatch between Canadian regulators' formulaic ROE resets and the real-world cost of debt and equity capital is very material.*[16]

Linda Ezergailis et al reiterated this point by noting that the current yield on the long Canada bond is no longer an accurate predictor of a regulated utility's cost of equity:

> *The Board conceded that factors that could potentially change TQM's cost of capital may not be captured in its previous approach, which relied on a single variable, the long Canada bond yield. We note that under the previous formula, recent declines in government bond yields resulted in a lower ROE for 2009, which is contrary to our view that the cost of capital for regulated companies has increased.*[17]

BMO Capital Markets declared that Canadian ROE formulas fail to take into consideration changes in industry or broad market conditions:

> *The major weakness here is that this formula does not take into account changes in industry conditions over time (shifting industry risks) nor does it take into account changes in the broad market, such as today's higher risk premiums (indeed, the flight to quality and strengthening of government treasuries has perversely eroded the allowed 2009 ROE to 8.57% at the very time investors are demanding higher returns).*[18]

Robert Kwan with RBC Capital Markets discussed the implications of the NEB's Decision on other jurisdictions within Canada:

> *Given the magnitude of the increased returns for TQM, we believe it may be difficult for the various provincial regulators to ignore the NEB decision. If there is no ROE relief, it may become difficult for provincially-regulated utility business to attract capital given what would be a significant difference in ROEs without a meaningfully different risk profile.*[19]

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16 Dafoe, Stephen. "Credit Analysis: Trans-Quebec & Maritimes Pipeline Inc." Scotia Capital. April 3, 2009. Page 5.

17 Ezergailis, Linda, Robert Hope and Avery Haw. "TQM Decision Has Positive Sector Implications." TD Newcrest. March 23, 2009. Page 33 of 43.

18 BMO Capital Markets, *North American Pipelines*, March 20, 2009.

19 Kwan, Robert. "Energy Infrastructure: Goodbye Formula, Hello Higher Returns." RBC Capital Markets. March 20, 2009. Page 3.

The NEB's TQM Decision has major implications for all Canadian regulated utilities. It is the first formal acknowledgment by a Canadian regulatory authority that the Formula is indeed "broken". The gradual decline in government bond yields has led to increasingly lower ROEs at a time when all logic indicates that equity costs are rising. This highlights the fundamental flaw with the Formula, which the Board noted in its Decision, that government bond yields do not capture all of the changes in a utility's cost of capital. In fact, though there is a strong historical relationship, current economic events illuminate that government bond yields and utility capital costs may be influenced by a completely different set of factors, and the relationship cannot be relied upon to hold. In Concentric's view, reliance upon any singular factor, without corroboration, in determining the utility cost of capital is a problematic approach that is subject to a high degree of error. The NEB Decision provides substantial support for provincial regulatory reviews of the ROE Formula. Currently, such reviews are ongoing in Alberta and are anticipated in British Columbia[20] and Quebec.[21].

FORMULA RESULTS DO NOT SATISFY THE PRINCIPLES OF THE FAIR RETURN STANDARD

Through the research and analysis that Concentric conducted in its studies for the OEB and Hydro One and the CLD, as well as the evidence Concentric presented in its testimony in the ongoing Alberta Generic Proceeding, we have measured the adequacy of allowed returns for Canada's utilities through several alternative screens. Each of these measures points to the same conclusion: there is a deficiency between any reasonable measure of "fair" and currently allowed returns. As pictured previously in Figure 7, and measured against average U.S. utility returns, a "fairness deficit" has prevailed for a decade, and has grown in recent years under the current Formula.

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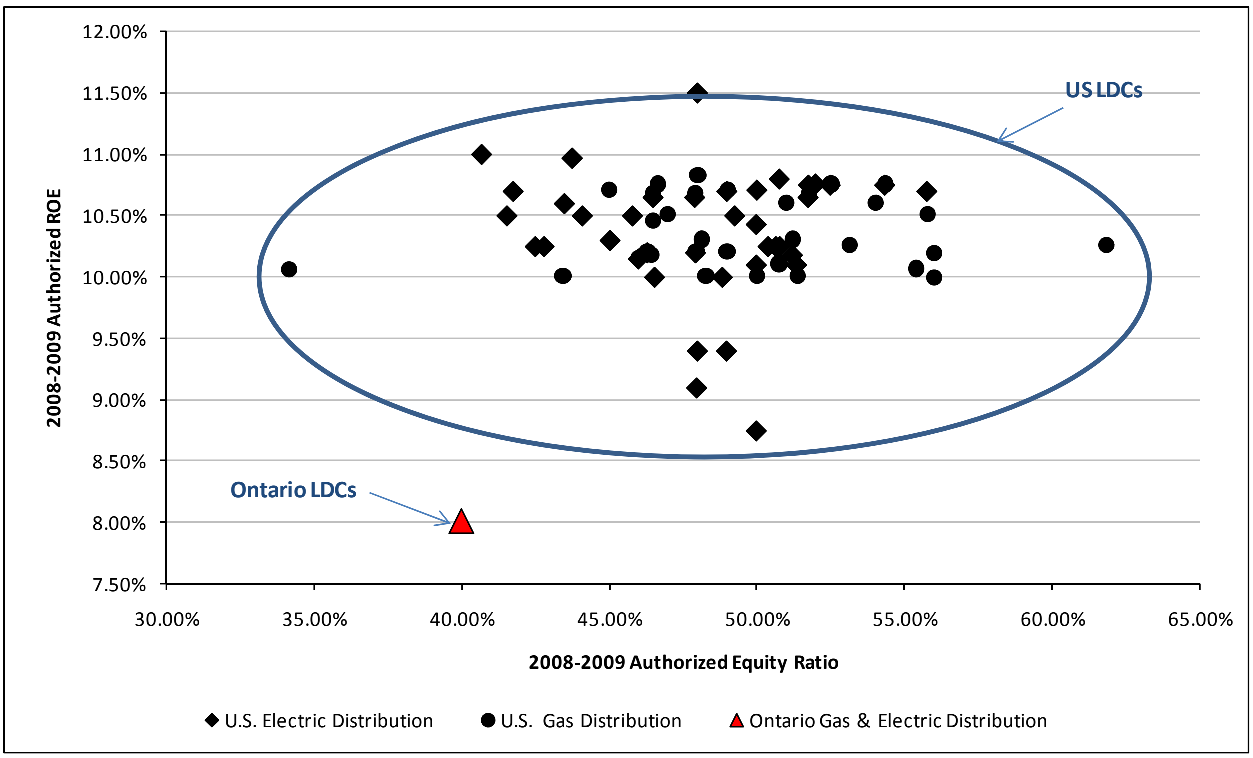
20 Terasen Gas 2008 Annual Report, at 25. Terasen makes the following statement: "Fair regulatory treatment that allows Terasen Gas and TGVI to earn a fair risk adjusted rate of return comparable to that available on alternative, similar risk investments is essential for maintaining service quality as well as ongoing capital attraction and growth. Since 1994, subject to minor modifications, the allowed ROE has been set based on a formula linked directly to forecast 30-year Canada Bond yields that have steadily declined in recent years. It is essential that the Company maintain good relationships with its various regulators and customer representatives. Terasen Gas and TGVI will be challenging the current generic ROE adjustment mechanism and increases to deemed equity thickness to more fair and appropriate levels. The Company intends to file an application with the BCUC in the second quarter of 2009.

21 Gaz Metro filed its intent to submit a rate application on March 2, 2009, and has indicated that it will be proposing modifications to the method of calculating ROE and to its capital structure.

Based on the foregoing assessment, the results produced by the current Formula do not meet the fairness standard that serves as the cornerstone of utility regulation. This places Ontario's utilities, their shareholders, and ultimately consumers, at a distinct disadvantage in contrast to their peers. Eventually, this leads to an inefficient deployment of resources and causes a loss of confidence in the regulatory compact that the Board upholds.

Another perspective on reasonableness can be found in Figure 10. Figure 10 shows that every gas and electric utility in the U.S. has an ROE substantially higher than the Ontario Formula rate, and all but one with substantially greater equity levels.

Figure 10: Comparison of U.S. Gas and Electric Utility ROEs and Equity Ratios to the Ontario Formula Result



In researching the causes for the gap in returns, there are no macroeconomic factors, regulatory risks, operating risks, or financial conditions of a sufficient magnitude to justify the disparity in returns between Ontario's utilities and their U.S. counterparts. Some argue that Ontario's utilities are less risky or that the regulatory environment is more supportive as a basis for this gap. Concentric has examined the operating and financial characteristics of the utility companies, the regulatory regimes in which they operate, the macro-economic environment, and the ability of utilities to recover expenses and adjust revenues in the U.S. and Ontario. The results of these analyses repeatedly indicate that there is sufficient basis for comparison between the two countries and in Concentric's view, there are no appreciable differences that would justify the disparity that currently exists between the U.S. and Ontario ROE awards. The widespread adoption of a formula tied directly to steadily declining government bond yields in Canada is the principal cause.

This conclusion was reinforced by the NEB in its recent TQM Decision where the Board concluded:

> *A fair return on capital should, among other things, be comparable to the return available from the application of the invested capital to other enterprises of like risk and permit incremental capital to be attracted to the regulated company on reasonable terms and conditions. TQM needs to compete for capital in the global market place. The Board has to ensure that TQM is allowed a return that enables TQM to do so. Comparisons to returns in other countries would be useful, but challenging, in terms of differences in business risks and business environment. As a result, the Board is of the view that pipeline companies operating in the U.S. have the potential to act as a useful proxy for the investment opportunities available in the global market place.*

Additionally, current conditions in financial markets are making it more difficult to raise debt or equity capital on reasonable terms. Utilities must maintain their financial flexibility in order to meet their continued obligations to provide safe and reliable service to their customers. Some degree of regulatory support during this turbulent economic period would help to assure the continued financial strength of Ontario's utilities. Considering the capital needs of the Province's utilities to fund system expansions to accommodate economic growth, this is particularly important.

V. REASONABLENESS OF SHORT-TERM AND LONG-TERM DEBT RATES

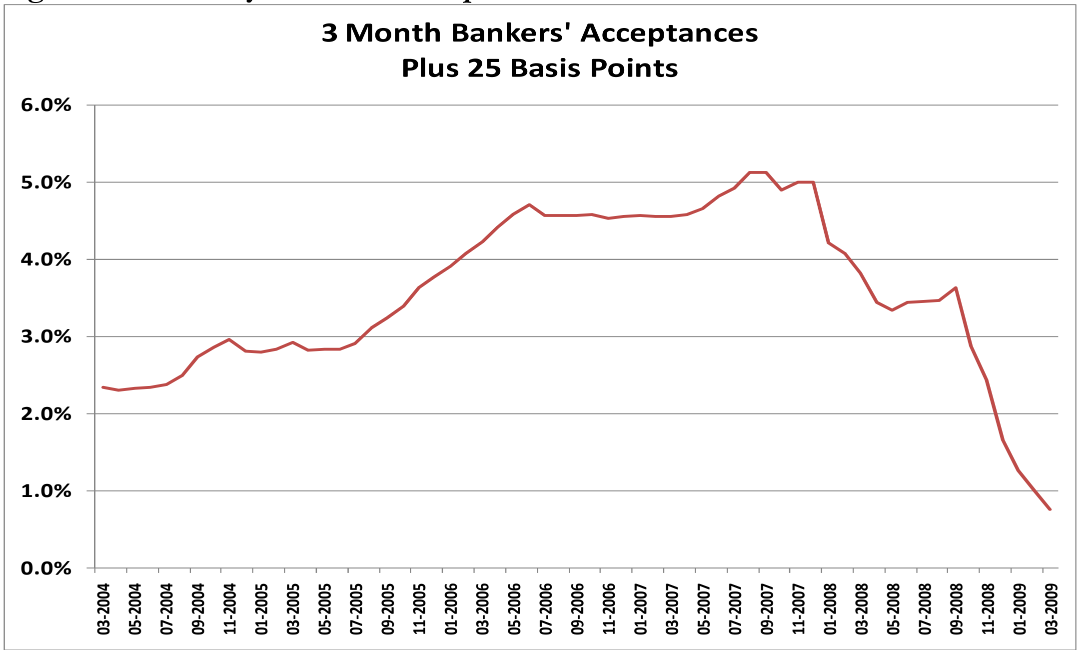
LONG-TERM DEBT RATE

The yields on Canadian Corporate A-rated bonds have risen sharply as investors have re-priced corporate risk in the context of the recession and failures of previously credit-worthy entities. This has affected highly-rated corporate issuers, including utilities. Fortunately, the Board's Formula for the deemed long-term debt rate is tied to Long Canadas and the average spread between investment grade (A/BBB) bond yields. The produced result has certainly been affected by current financial conditions, but is better able to track the actual cost of utility debt issuances given the appropriate link to corporate bond spreads.

SHORT-TERM DEBT RATE

The Board's deemed short-term debt rate is tied to three-month banker's acceptance rates plus a fixed spread of 25 basis points. It is Concentric's understanding that the 25 basis point differential no longer reflects short-term borrowing costs. The credit spreads on short-term debt have risen sharply and are currently about 10 times the normal historical levels. Current pricing for bank lines reflect a standby fee of 40-50 basis points and will require 150 – 200 basis points to draw on the credit line. While the banker's acceptance rate has continued to decline, as illustrated in Figure 11, the differential over the banker's acceptance rate has increased from 35 – 45 basis points to as high as 250 basis points for drawn-down renewals. The current deemed short-term debt cost therefore does not reflect current market conditions.

Figure 11: Monthly Bankers' Acceptances



Concentric proposes that the Commission adopt a similar approach to assigning short-term debt costs as that employed for long-term debt costs; and that is to provide for a calculation of the current spread over the last 30 days to forecasted LIBOR or bankers' acceptance rates. Currently, the short-term debt parameter is significantly understated.

VI. CONCLUSIONS

Based on the foregoing analysis, we reach conclusions related to each of the specific questions raised for consideration by the Board.

1. *How do the current economic and financial conditions affect the variables (i.e., Government of Canada and Corporate bond yields, bankers' acceptance rate, etc.) used by the Board's Cost of Capital Methodology?*

There is little doubt that the current economic and financial situation has had a material impact on the variables used by the Board in its methodology. Specifically:

- Long Canada Bonds have steadily declined over the past several years, and this decline has accelerated as a result of the flight to quality in global financial markets over the past six months. Long Canadas are now yielding the lowest rates since the 1940s. Simultaneously, the cost of equity, by any reasonable measure, has increased sharply. Financial analysts estimate that the market equity risk premium (over the risk free rate) is now in the range of 8 - 10 percent.[22] As a result, the single driver of cost of equity in the Formula (Long Canadas) is not able to track the actual cost of equity. This situation has evolved with the decade-long decline in government bond yields, and has been exacerbated by current financial markets.
- Simultaneously, the yields on Canadian corporate A-rated bonds have risen sharply as investors have re-priced corporate risk in the context of the recession and failures of previously credit-worthy entities. This has affected highly-rated corporate issuers, including utilities. Fortunately, the Board's Formula for the deemed long-term debt rate is tied to Long Canadas and the average spread between investment grade (A/BBB) bond yields. The produced result has certainly been affected by current financial conditions, but is better able to track the actual cost of utility debt issuances given the appropriate link to recent corporate bond spreads.
- The Board's deemed short-term debt rate is tied to 3-month bankers' acceptance rates plus a fixed spread of 25 basis points. The differential over the banker acceptance rate has

[22] JP Morgan, The Most Important Number in Finance – The Market Risk Premium (November 2008)

increased from 35 – 45 basis points to roughly 250 basis points for drawn-down renewals. The current deemed short-term debt cost, therefore, does not reflect current market conditions.

2. *In the context of the current economic and financial conditions, are the values produced by the Board's Cost of Capital methodology and the relationships between them reasonable? Why, or why not?*

The values produced by the current cost of capital methodology are not reasonable in the context of current market conditions. The deemed long-term debt rates follow more closely with actual market conditions since it is based on actual current spreads. The short-term borrowing spread no longer reflects actual market conditions and should be modified to incorporate current spreads over bankers' acceptances.

- As illustrated through comparisons of returns earned by other utilities, the ROE tied to a single variable, the long Canada bond, is not producing reasonable results. The gap is estimated between 146 – 218 basis points, representing the differences between the average 2008 Ontario allowed ROE; and those allowed for U.S. utilities and for TQM (by the NEB), respectively. Factoring in current market conditions, this gap is estimated at 279 basis points with the 2009 Formula.

2.1 If the values are not reasonable, what are the implications, if any, to a distributor?

The implications of a below market ROE for a distributor are several. Recognizing that Concentric's analysis indicates that a gap has existed for several years, there is a compounding effect over time. Among these implications are:

- Reduced earnings to fund re-investment in the utility, potentially diminishing service quality and the ability to meet demand growth over time. Because utilities have long-term planning horizons, the problems caused by under-investment in infrastructure projects and system sub-optimization may not materialize for several years.
- Reduced earnings for dividends to shareholders, diminishing the value of existing shares and impacting the ability to compete for additional equity capital. The ROE Formula, while

well-intentioned, has resulted in a persistent and expanding gap in returns, which causes Canadian utilities to be less attractive to investors than other companies of comparable risk.

- Negative impacts on debt coverage ratios and credit metrics, potentially increasing the cost of debt capital and this impact is more pronounced where high debt/equity ratios prevail.
- Inability to meet the fairness standard, undermining trust in the Ontario regulatory compact and discouraging long-term utility investment.

3. *What adjustments, if any, should be made to the Cost of Capital parameter values to compensate or correct for the current economic and financial conditions?*

It is Concentric's opinion that there is no quick fix that will put the Formula on solid ground. Ultimately, a more comprehensive proceeding should be initiated by the OEB to identify and resolve issues associated with the Formula that will ensure the consideration of corroborating factors and provide utilities an opportunity to earn a fair return under a variety of economic conditions. To properly estimate the cost of capital, with emphasis on the cost of equity, requires the use of financial market analytics and corroborating sources. This may be accomplished using traditional techniques such as the CAPM, DCF, Equity Risk Premium, and their variations, including ATWACC. Short of such analysis, which would probably entail a generic cost of capital proceeding, it would be difficult to estimate the degree of adjustment required to re-base the ROE or correct for current market conditions. The magnitude of the 2008 gap, as noted above, is probably at least 146 – 218 basis points, but this would be a crude estimate without the benefit of appropriate capital structure, business and financial risk assessment necessary to re-base ROEs for Ontario's utilities.

4. *Going forward, should the Board change the timing of its Cost of Capital determination, for instance, by advancing that determination to November?*

The primary consideration with respect to timing is to establish parameters that are close enough to the test year to provide forward looking estimates, but allow adequate time to incorporate the parameters for the subject year into the necessary budgeting functions. We understand that a number of LDCs have expressed concern about a rate year that commences prior to the setting of rates. Since the fiscal year for Ontario LDCs has been mandated to commence on January 1st, a number of LDCs will be proposing a January 1st rate year in future cost of service rate applications. On that basis, cost of capital rates would have to be set several months earlier than the inception of the rate year.

5. *Are there other key issues that should be considered if the Board were to adjust any or all of the Cost of Capital parameter values produced by the application of its established formulaic methodology?*

Under the ROE Formula, as currently designed, the OEB depends on a single variable (government bond yields) as the platform for utility ROE and the regulator is precluded from exercising informed judgment in the determination of a fair return. Current turmoil in financial markets highlights this fundamental problem. A temporary fix may reduce the impact, but will not address the fundamental problem. Concentric believes the OEB and utility stakeholders will be better served by a comprehensive examination of alternative approaches to capital cost estimation. This will allow the Board to determine an approach that both allows sufficient flexibility to adapt to changing market conditions, and one that provides sustainably fair returns.

REPORT OF PAUL R. CARPENTER, PHD

FOR

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April 16, 2009

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I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

On March 16, 2009, the Ontario Energy Board (the "Board", or the "OEB") initiated a consultative process "to help it to determine whether current economic and financial market conditions warrant an adjustment to any of the Cost of Capital parameter values (i.e., the Return on Equity, Long Term Debt rate, and/or Short Term Debt rate)" recently determined by the Board for 2009 cost of service applications for electric distributors.[1] The values of the 2009 Cost of Capital parameters are:

Parameter	Value for 2009 Cost of Service Applications (assuming May 1, 2009 implementation date for rate changes)
Return on Equity	8.01%
Long-Term Debt Rate	7.62%
Short-Term Debt Rate	1.33%

The Board noted that the spread between the Return on Equity ("ROE") and Long Term Debt has declined to 39 basis points, and noted the deterioration in economic and financial market conditions in 2008 and 2009. The Board stated that it is considering whether these circumstances warrant the Board adjusting any or all of the Cost of Capital values produced by its current formula-based methodology.

In soliciting comments on whether it should adjust the parameters determined under its formula-based methodology, the Board emphasized that it was not reconsidering the formula-based methodology itself. The Board stated:

> The Board's established formulaic methodology itself is not at issue. The objective of this consultation is not to reconsider that established methodology, but rather to test whether the values produced, and the relationships among them, are reasonable in the context of the current economic and financial market conditions.

Enbridge Gas Distribution Inc. ("EGDI") asked me to comment on: (1) whether the results of the Board's current formula-based methodology account for recent changes in capital market conditions and the Ontario business environment, and (2) the key findings of the National

1 "The Cost of Capital in Current Economic and Financial Market Conditions," Board File No. EB-2009-0084, March 16, 2009.

Energy Board's recent Decision in RH-1-2008 that are applicable to utility cost of capital in Ontario.

My conclusions can be summarized as follows:

- Recent changes in capital market conditions and the business environment for utilities in Ontario are not currently being accounted for in the results of the OEB's formula approach to ROE determination.
  - The fact that the results of the formula-based methodology are not producing a fair return for 2009 is clearly established by the relationship between the formula ROE and current bond yields.
  - Ontario's utilities have been exposed to many changes in their business environment since the formula approach was first established by the Board in 1997 (for gas) and 1999 (for electricity). There have been significant changes in the level and volatility of energy commodity prices, the health of the industrial sector, energy conservation and environmental policies, and regulation. The effects of these changes on utility business risk are not being captured in current allowed returns.
- In its recent Decision in RH-1-2008 the NEB made several key findings that are very applicable to utility cost of capital in Ontario:
  - First and foremost, the fair return standard is appropriately directed at *total* return on capital and not just ROE. One consequence of this principle is there can be no assurance that simple adjustments to the parameter values involved in the OEB's formula-based methodology would result in total returns that are fair.
  - Second, it is appropriate to give consideration to long-term, fundamental business risks in determining the fair return on total capital, and that it may be difficult for regulators to deal with the realization of such risks as they unfold.
  - Third, under the comparable investment standard it is wholly appropriate to make comparisons with the returns available to utilities in the U.S., given the growing integration of North American capital and energy markets and the similarity of the regulatory systems in both countries.

- Finally, adjustment of allowed ROE's with changes in the long Canadian bond do not account for the recent changes in the financial and energy market environment faced by utilities in Canada.

- Given the fact-specific nature of these issues, it is important that the OEB make a careful and reasoned examination of the business and financial environment currently faced by the asset-intensive utility industry in Ontario. Consequently, the OEB should consider convening a generic proceeding to evaluate and consider changes to its methodology for establishing fair returns.

My qualifications as an economist specializing in the natural gas industry are described in Section IV and in Attachment A to this statement.

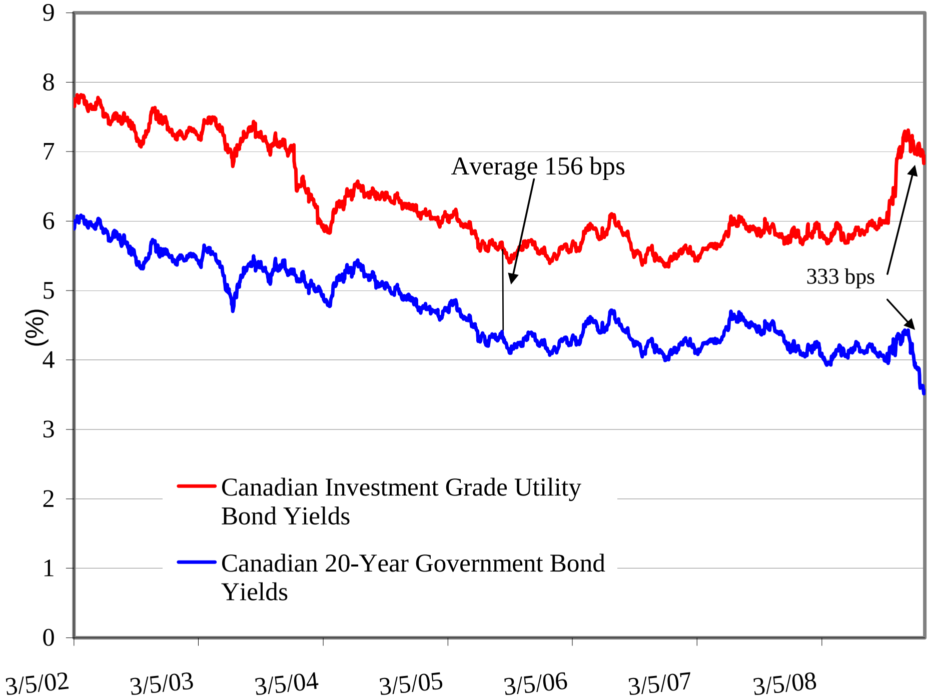
II. THE RESULTS OF THE OEB'S FORMULA-BASED APPROACH ARE NOT PRODUCING FAIR RETURNS ON CAPITAL

A. CHANGES IN THE FINANCIAL MARKET ENVIRONMENT REVEAL THAT THE BOARD'S FORMULA RESULTS FOR 2009 ARE CLEARLY UNREASONABLE

The fact that the results of the formula-based methodology are not producing a fair return for 2009 is clearly established by the current relationship between the formula ROE and current bond yields. As the Board noted, the spread between allowed return on equity and the long-term debt rate is only 39 basis points. In 1999, when the OEB adopted the formula-based methodology for electric distributors, the spread between allowed return on equity and the long-term debt rate was roughly 260– 310 basis points, depending on the size of the distributor.

The problem, in part, is that the formula considers only one change when making annual adjustments to allowed returns: the change in Canadian long bond yields. However, changes in the cost of capital may not be adequately reflected in changes in government interest rates. Utilities cannot raise capital at government rates. Changes in government interest rates are driven principally by monetary and fiscal policy. Changes in utilities' cost of capital depend on many factors, including financial market conditions, energy market conditions, and changes in investor risk perceptions. And, as Figure 1 indicates, utility debt costs and government interest rates are diverging significantly in the current financial and economic environment in Canada.

Figure 1
Canadian Utility Bond Yields vs. Government Bond Yields



While the average spread between Canadian utility and government bond yields was 156 basis points over the period March 2002 through December 2008, this spread has now widened to 333 basis points. These data strongly suggest that the cost of equity for Canadian utilities is likely increasing as well, contrary to what the formula is now producing.

A lack of clear signs of financial distress and disincentive to invest in the utility industry is not evidence that the current returns are fair. Utilities have many reasons to continue to make investments in their systems, even at returns that are lower than returns they could earn elsewhere on investments of comparable risk. Utilities have an obligation to make on-going investments to insure that their systems are safe and reliable, and they may have incentives to make investments at low returns in order to protect their existing markets. Moreover, any signs of financial distress may come too late, particularly with respect to the cost of equity. Debt has a more senior claim on cash flow than equity. Therefore, by the time debt is downgraded (particularly if it is downgraded to below investment grade status) the cost of equity may have already risen substantially.

B. Recent Changes in the Utility Business Environment in Ontario Suggest that the Board's Formula Results for 2009 are Unlikely to Be Fair

Ontario's utilities have been exposed to many changes in their business environment since the formula approach was first established by the Board in 1997 (for gas) and 1999 (for electricity). There have been significant changes in the level and volatility of energy commodity prices, the health of the industrial sector, energy conservation and environmental policies, and regulation. These changes are not being captured by the current formula-based methodology for determining the allowed return on capital. Any reconsideration of the parameters produced by the current formula should give thorough and reasoned consideration to the business environment in which Ontario utilities now operate.

The determination of a fair return on capital typically considers the business environment in assessing business risk. With regard to business risk, two types of risks are most important: "systematic" risks and "fundamental" risks. Systematic risks are risks that are correlated with movements in the overall economy, and thus they are not the kind of risks that can be diversified away by equity investors' holding portfolios of stocks or broadly-based mutual funds. Systematic risks associated with the energy distribution business include uncertainties in the demand for, and supply of, distribution services that are affected by changes in economic activity, including incomes, prices and governmental policies including environmental concerns. Fundamental risks are risks that relate to structural uncertainties surrounding the long-term recovery of, and the return on, capital investment. Fundamental risks are particularly important in the utility industry due to the "sunk" nature of utility assets and the inability to redeploy them easily or quickly to higher-valued uses should market conditions worsen. Further, it may be difficult for regulators to respond to fundamental risks.[2] The changes in business environment that I discuss here have increased the systematic and fundamental risk of Ontario utilities. They are the kinds of changes that merit careful consideration in determining fair overall returns.

Increased commodity prices and volatility have been a particular feature of the business environment for Ontario utilities since the formula approach to rate of return was first introduced. For example, the increased level and volatility of natural gas prices has important implications for both natural gas and electricity distributors that rely on gas-fired generation. For gas distribution customers, the commodity cost of gas is the largest single element of their bills, and higher prices and volatility translate into more uncertain demand and greater competition between gas and alternative fuels. For electricity distributors that rely on gas-fired generation, higher and more volatile gas prices translate into higher electricity prices and increased uncertainty with respect to future growth in gas-fired generation investments.

Industrial demand for energy is impacted negatively by higher and more volatile energy commodity prices, but it is also impacted by broader economic conditions. The industrial sector is weaker than it was when the formula-based methodology was put in place. The auto industry in Ontario offers a particularly dramatic example. Auto parts manufacturing and assembly represents approximately 20 percent of Ontario's total manufacturing output. This sector has experienced several large plant closures in the past 10 years, and has been hit particularly hard by the current economic crisis. It recently received a large infusion of capital from the Canadian government.

New environmental policies have been enacted since the formula-based methodology was put in place. These policies have the potential to significantly alter the competitive landscape among competing fuels and energy sources over the coming years. For example, the Ontario government released a climate change action plan in August 2007 that contains targets for reducing Ontario's greenhouse gas emissions (including phasing out coal-fired electric power plants and adding renewables) and programs and incentives to increase energy efficiency in the province.[3]

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[2] See NEB Decision RH-1-2008, p. 46. Other risks may be more short-term in nature and relate to the period-to-period variability in the utilities earnings. These risks will be affected by the regulatory model under which the utility operates. For example, incentive regulation schemes may introduce greater short-term variability in earnings than would be the case under traditional cost-of-service regulation.

With respect to regulation, there have been some notable changes since 1997. First, the OEB has evolved toward greater use of incentive regulation mechanisms for the utilities it regulates. All else equal, incentive regulation schemes tend to increase the earnings volatility risk to which the utilities are exposed. The nature and extent of such exposure depends on the particular utility and incentive arrangement.

This discussion of changes in the business environment faced by Ontario utilities is by no means exhaustive. The changes I discuss can affect different utilities' business risk in different ways. An evaluation of the fair total return for a particular utility or group of similar utilities requires a thorough evaluation of their current business environment and its impact on business risk.

III. KEY FINDINGS IN THE NEB'S RH-1-2008 DECISION ARE APPLICABLE TO ONTARIO

The NEB made several key findings in its Decision in RH-1-2008 that are applicable to utility cost of capital in Ontario. Most importantly, the NEB found that the fair return standard was appropriately directed at the *total* return on capital, not just return on equity. The NEB stated that the formula-based approach suffers from the fact that it separates "two elements that are inevitably linked: capital structure and return on equity,"[4] and that "simply looking at the return on equity which provides only a partial understanding of the total return on capital." The NEB found that an approach that determines a fair overall return has several advantages over formula-based methodologies that determine return on equity and equity thickness separately. Most significantly:

(1) The NEB found that an approach that is directed at total return makes it easier to compare returns for companies of similar risk because it neutralizes differences due to financial risk.[5]

(2) The NEB found that a total return approach is more transparent because it relies on a single number (the total return on capital) in making comparisons between companies

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3 "Go Green: Ontario's Action Plan on Climate Change," August 2007.
4 National Energy Board, RH-1-2008, p. 19.
5 National Energy Board, RH-1-2008, p. 18.

of similar business risk. Thus, it does not require the regulator to make difficult evaluations of the capital structures specific to individual companies.[6]

(3) The NEB found that a total return approach is more consistent with the way companies make capital budgeting decisions.[7]

In deciding to use a methodology based on total return, instead of a formula-based methodology, to determine TQM's allowed return for 2007 and 2008, the NEB found that the adjustment of allowed ROE's with changes in the long Canadian bond do not account for recent changes in the financial and business market environment faced by Canadian utilities:

> The RH-2-94 Formula relies on a single variable which is the long Canada bond yield. In the Board's view, changes that could potentially affect TQM's cost of capital may not be captured by the long Canada bond yields and hence, may not be accounted for by the results of the RH-2-94 Formula. Further, the changes discussed above regarding the new business environment are examples of changes that, since 1994, may not have been captured by the RH-2-94 Formula. Over time, these omissions have the potential to grow and raise further doubt as to the applicability of the RH-2-94 Formula result for TQM for 2007 and 2008.[8]

Simple adjustments to the Cost of Capital parameters determined for 2009 under the Board's existing formula-based methodology are unlikely to result in fair overall returns. Under a formula-based methodology there is no necessary numerical connection between changes in the formula return on equity (which depends only on changes in the long Canada bond yield) or the deemed equity thickness and changes in the total return required by investors in the equity securities of the benchmark utility. Thus, it cannot be assumed that changes in formula return on equity or equity thickness adequately account for changes in financial market conditions or business risk without re-estimating the cost of capital using appropriate benchmarks.

The NEB found that it was appropriate to give consideration to long-term, fundamental business risks in determining the fair return on capital, and it found that changes in the business

6 National Energy Board, RH-1-2008, p. 19.
7 National Energy Board, RH-1-2008, p. 18.
8 National Energy Board, RH-1-2008, p. 17.

environment cast doubt on the continued applicability of the formula result for TQM.[9] The NEB undertook a thorough and detailed review of changes in TQM's business risk since the inception of the formula-based approach.[10] And, the NEB explained how a business risk evaluation would be used in two important ways under a total return approach to establishing a fair return:

> [A total return approach] requires a business risk analysis that would be used to assess how the risks of TQM have evolved since they were last considered by the Board. The business risk analysis would also be relied upon to select firms of comparable risks based on the traditional five factors (supply, market, competitive, regulatory and operational risks). Once comparable firms are selected, information can be extracted from those firms, including cost of equity, capital structure and cost of debt to derive an aggregate cost of capital. At each step of this process, judgment is necessary to select the inputs that would ultimately inform the determination of the cost of capital for TQM for 2007 and 2008.[11]

Any such analysis of the overall cost of capital for utilities in Ontario should include a thorough analysis of their current business environment, since very significant changes have been occurring in the market and infrastructure investment environment in which utilities in Ontario and throughout North America operate. Ultimately, the NEB gave great weight to its own evaluation of changes in the business risk environment on the overall fair return for TQM. The OEB should seriously consider undertaking a similar exercise in determining fair returns for the utilities it regulates in order to ensure that utilities in Ontario are compensated for changes in their business and financial risk environment.

Finally, the NEB found that it was entirely appropriate to rely upon comparisons with returns available to utilities in the U.S. in establishing a fair return for TQM. The NEB reached this conclusion based on the growing integration of North American capital and energy markets and the similarity of the regulatory systems in both countries:

> A fair return on capital should, among other things, be comparable to the return available from the application of the invested capital to other enterprises of like risk and permit incremental capital to be attracted to the regulated company on reasonable terms and conditions. TQM needs to compete for capital in the global

9 National Energy Board, RH-1-2008, p. 17.
10 National Energy Board, RH-1-2008, p. 45-51.
11 National Energy Board, RH-1-2008, p. 18.

> market place. The Board has to ensure that TQM is allowed a return that enables TQM to do so. Comparisons to returns in other countries would be useful, but challenging, in terms of differences in business risks and business environment. As a result, the Board is of the view that pipeline companies operating in the U.S. have the potential to act as a useful proxy for the investment opportunities available in the global market place.[12]
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> *****
>
> Overall, the Board finds that the risks resulting from the regulatory environment are higher for U.S. pipelines than for Canadian pipelines, and finds that this was also true in 1994. However, the Board is of the view that the risks faced by TQM and those faced by U.S. pipelines are not so different as to make them inappropriate comparators. The Board accepts that there are many similarities between the risks faced by pipelines in the two countries. This is due to the two regulatory models sharing, to a large extent, the same fundamental principles. Moreover, Canadian and U.S. pipelines operate in what the Board views as an integrated North American natural gas market, which informs the choices made by regulators in the different jurisdictions.[13]

As a part of any review of the cost of capital for Ontario's utilities, the Board will need to develop current and relevant benchmarks and data sets for estimating the cost of capital. In its RH-1-2008 decision the NEB recognized the similarity in the regulatory environments between the US and Canada and concluded that it was "satisfied that the evidence establishes that TQM and U.S. LDCs are sufficiently similar in risk so as to make comparisons meaningful."[14] In my opinion, the same conclusion can be reached with respect to comparisons between U.S. and Canadian electricity distribution companies and U.S. and Canadian gas distribution companies.

IV. QUALIFICATIONS

I am an economist specializing in the fields of industrial organization, finance and energy, and regulatory economics. I received a Ph.D. in Applied Economics and an M.S. in Management from the Massachusetts Institute of Technology, and a B.A. in Economics from Stanford University. I have been involved in research and consulting on the economics and regulation of the natural gas, oil and electric utility industries in North America and abroad for twenty-five years. I frequently have testified before federal, state, and Canadian regulatory commissions, in

12 NEB Decision RH-1-2008, p.67.
13 NEB Decision RH-1-2008, p.68.

federal court and before the U.S. Congress, on issues of pricing, competition, and regulatory policy in these industries. Outside of North America, I have advised governments and regulatory bodies on the structure of their natural gas markets and the pricing of gas transmission services. These assignments have included testimony before the U.K. Monopolies and Mergers Commission and the Australian Competition Tribunal, and advice to the governments of, and regulators in, Greece, Ireland, the Netherlands, New Zealand, and Australia.

I have been extensively involved in the evaluation of the economics and regulation of the natural gas industry in North America. In Canada, I have advised pipeline companies and have previously testified before the NEB and the Alberta Energy and Utilities Board on matters relating to pipeline competition and capacity expansion, including the Alliance Pipeline Ltd. certification proceeding. I gave evidence on business risk previously before the NEB in the multi-pipeline cost of capital case, on behalf of Foothills Pipe Lines, and in more recent NEB proceedings on behalf of TransCanada PipeLines Limited and Trans Québec and Maritimes Pipeline. I recently provided written evidence on business risk before the Alberta Utilities Commission ("AUC") on behalf of Nova Gas Transmission as part of the AUC's 2009 Generic Cost of Capital proceeding, and before the Ontario Energy Board on behalf of Union Gas Limited and Enbridge Gas Distribution Inc. as part of their 2007 rate applications. I provided written evidence on business risk and appeared before the Régie de l'Energie on behalf of Gaz Métro as part of its 2008 rate application. Further details of my educational and professional background, as well as a listing of my publications, are provided in my curriculum vitae, which is appended to this evidence as Attachment A.

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[14] NEB Decision RH-1-2008, p.68.

ATTACHMENT A

RESUME OF PAUL R. CARPENTER, PHD

PAUL R. CARPENTER **Principal**

Dr. Carpenter holds a Ph.D. in applied economics and an M.S. in management from the Massachusetts Institute of Technology, and a B.A. in economics from Stanford University. He specializes in the economics of the natural gas, oil and electric utility industries. Dr. Carpenter was a co-founder of Incentives Research, Inc. in 1983. Prior to that he was employed by the NASA/Caltech Jet Propulsion Laboratory and Putnam, Hayes & Bartlett, and he was a post-doctoral fellow at the MIT Center for Energy Policy Research. He is currently a Principal and Chairman of *The Brattle Group*.

AREAS OF EXPERTISE

Dr. Carpenter's areas of expertise include the fields of energy economics, regulation, corporate planning, pricing policy, and antitrust. His recent engagements have involved:

- *Natural Gas and Electric Utility Industries*: consulting and testimony on nearly all of the economic and regulatory issues surrounding the transition of the natural gas and electric power industries from strict regulation to greater competition. These issues have included stranded investments and contracts, design and pricing of unbundled and ancillary services, evaluation of supply, demand and price forecasting models, the competitive effects of pipeline expansions and performance-based ratemaking. He has consulted on the regulatory and competitive structures of the gas and electric power industries in the U.S., Canada, the United Kingdom, continental Europe, Australia and New Zealand.

- *Antitrust*: expert testimony in several of the seminal cases involving the alleged denial of access to regulated facilities; analysis of relevant market and market power issues, business justification defenses, and damages.

- *Regulation*: studies and consultation on alternative ratemaking methodologies for oil and gas pipelines, on "bypass" of regulated facilities before the U.S. Congress; advice and testimony before several state utility commissions and the National Energy Board of Canada on new facility certification policy.

- *Finance*: research on business and financial risks in the regulated industries and testimony on risk, cost of capital, and asset valuation for network industries, airports and seaports in the U.S., Canada., Australia and New Zealand.

PROFESSIONAL AFFILIATIONS

International Association of Energy Economists
American Bar Association (Antitrust Section)
American Economic Association

ACADEMIC HONORS AND FELLOWSHIPS

Stewart Fellowship, 1983
MIT Fellowships, 1981, 1982, 1983
Brooks Master's Thesis Prize (Runner-up), MIT, 1978

PUBLICATIONS

"The Advent of U.S. Gas Demand Destruction and Its Likely Consequences for the Pricing of Future European Gas Supplies," (with Carlos Lapuerta and Morten Frisch), 16 March 2005.

"REx Incentives: Performance Based Ratemaking (PBR) Choices that Reflect Firms' Performance Expectations," (with Johannes P. Pfeifenberger and Paul C. Liu), *The Electricity Journal*, November 2001.

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SPEECHES/PRESENTATIONS

"LNG Access Policy and California," California Resources Agency Workshop on LNG, June 1, 2005.

Opening Remarks at the Eighth Central and Eastern European Power Industry Forum (CEEPIF 2001), Budapest, March 29, 2001.

"CPUC v. El Paso Merchant Energy, et al., FERC Docket No. RP00-241-000," ABA Forum, Washington, DC, September 6, 2001.

"Overseas Experience – Lessons for Australian Gas and Power Markets from California and Europe," 2001 Gas Industry Forum, The Australian Gas Association, Melbourne, Victoria, Australia, June 26, 2001.

"Liberalizing Energy Markets: Lessons from California's Crisis," 20th Annual Conference on US-Turkish Relations, Washington, DC, March 27, 2001.

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"Appropriate Regulation in the Local Marketplace," Interregional Natural Gas Symposium, Center for Public Policy, University of Houston, November 30, 1988.

"Market Forces, Antitrust, and the Future of Regulation of the Gas Industry," Symposium on the Future of Natural Gas Regulation, American Bar Association, Washington D.C., April 21, 1988.

"Valuation of Standby Tariffs for Natural Gas Pipelines," Workshop on New Methods for Project and Contract Evaluation, MIT Center for Energy Policy Research, Cambridge, March 3, 1988.

"Long-term Structure of the Natural Gas Industry," National Association of Regulatory Utility Commissioners Meeting, Washington D.C., March 1, 1988.

"How the U.S. Gas Market Works"or Doesn't Work," Ontario Ministry of Energy Symposium on *Understanding the United States Natural Gas Market*, Toronto, March 18, 1986.

"The New U.S. Natural Gas Policy: Implications for the Pipeline Industry," Conference on Mergers and Acquisitions in the Gas Pipeline Industry, Executive Enterprises, Houston, February 26-27, 1986.

Various lectures and seminars on U.S. natural gas industry and regulation for graduate energy economics courses at Massachusetts Institute of Technology, 1984-96.

Panelist in University of Colorado Law School workshop on state regulations of natural gas production, June 1985. (Transcript published in *University of Colorado Law Review*.) "Oil Pipeline Rates after the *Williams* 154 Decision," Executive Enterprises, Conference on Oil Pipeline Ratemaking, Houston, June 19-20, 1984.

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TESTIMONIAL EXPERIENCE

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Before the Pennsylvania Public Utility Commission, *Application for Approval of the Merger of Public Service Enterprise Group and Exelon Corporation*, Docket No. A-110550F0160, June 2005, August 2005, September 2005.

Before the National Energy Board of Canada, in the matter of *TransCanada Pipelines LTD.*, RH-2-2004 Phase II, Cost of Capital, January 2005.

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THE COST OF CAPITAL IN CURRENT ECONOMIC
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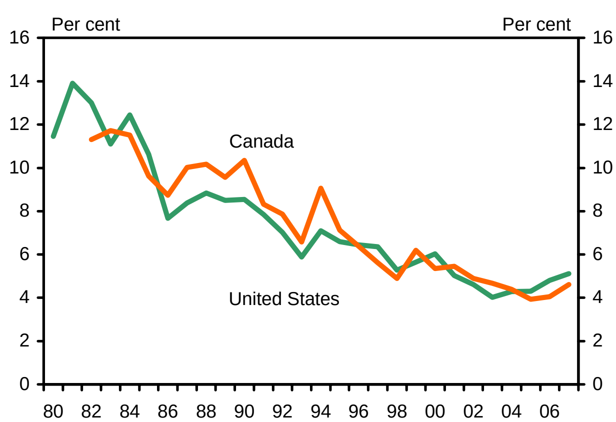
THE SHAPE OF YIELDS TO COME: AN OUTLOOK FOR U.S. AND CANADIAN INTEREST RATES TO 2020

A dominant financial theme over the past three decades has been the secular decline in interest rates across the industrial world, including in Canada. This downward trend has made forecasting the long-term prospects for money market rates and bond yields challenging. One must identify which factors contributing to the decline are structural and which are cyclical or transitory. It is also necessary to speculate about what new forces might come into play shaping yields in the years ahead.

In the sections that follow, we review the various explanations for the prevailing low interest rate environment and outline three alternative approaches to projecting the average level of yields out to 2020. The primary focus is the outlook for Canadian yields, but the analysis has a major international dimension because Canadian fixed income products trade in the context of a global market, which is dominated by developments in U.S. Treasuries.

CANADA & U.S. 10-YEAR GOV'T BOND YIELDS



Source: Bank of Canada, U.S. Federal Reserve, Haver Analytics

HIGHLIGHTS

- **Interest rates will fluctuate over business cycles and in response to changing inflation risks, but the low and relatively stable rate environment will persist in the U.S. and Canada over the long haul.**
- **Aging populations point to a gradual decline in the neutral level of the interest rates in the decades ahead.**
- **From 2007 to 2020, the average level of U.S. short-term rates is expected to be 3.4% to 4.1%, while 10-year Treasuries are projected to average between 3.7% to 5.4%, with both having a bias towards the bottom half of the range over the next 10-15 years.**
- **Canada's superior fiscal outlook and the likelihood of weaker global demand for U.S. dollars and U.S. Treasuries suggest Canadian fixed income markets will outperform. As a result, Canada will lose its traditional country risk premium and modest negative Canada-U.S. interest rate spreads will be the norm.**
- **U.S. and Canadian yield curves will, on average, be positively sloped (i.e. normal), but very flat. Canadian fixed income outperformance could lead to a flatter curve than in the U.S.**
- **Volatility in long-term bond yields will prove limited, with the result that changes in the yield curve will be dominated by adjustments to monetary policy and movements in short-term rates.**

The central conclusions for Canada and the U.S. are that the low and stable interest environment is likely to persist, with nominal yields averaging roughly in a range of 3.4% to 5.4%. There is a bias towards the lower half of the range over time, as demographic factors reduce the neutral level of interest rates in both countries between today and 2020. Yield curves will average a normal upward slope, but with relatively tight spreads between short-term and long-term rates. While Canadian interest rates will be heavily influenced by the path of U.S. yields, the superior Canadian fiscal outlook and the possibility of weaker global demand for U.S. dollars and U.S. Treasuries suggest that the Canadian fixed income market can outperform. Negative Canada-U.S. interest rate spreads should be the norm and Canada is likely have a flatter yield curve than the United States.

Structural decline in interest rates

One of the most dramatic and well known financial trends in recent decades has been a remarkable decline in interest rates. From an annual average peak of 15.52% in 1981, the yield on the long-term Government of Canada bond benchmark tracked by the Bank of Canada fell to 4.02% in 2005. The U.S. experience has been similar, with the yield on 10-year Treasuries dropping from an average of 13.91% to below 4% in 2003. In fact, the decline in long-term interest rates has been experienced across the entire industrialized world, but to differing degrees and at differing rates. The natural question is what has driven this protracted trend?

The experience of the 80s and 90s

Much of the retreat in yields experienced in the 1980s

Key determinants of interest rates

It is worth reviewing the key determinants of long-term interest rates. At the short-end of the yield curve, money market rates are anchored by central bank benchmark short-term rates – the overnight rate in Canada and the fed funds rate in the United States. Over any significant time horizon, one would expect monetary policy to be set, on average, at a neutral stance. The neutral level of rates is one that neither adds stimulus to the economy, nor applies the brakes, and is consistent with economic growth at its long-term trend potential pace. However, the neutral level is not constant.

Nominal short-term rates are influenced by inflation, while the underlying short-term real (after-inflation) rates are a product of a variety of economic factors. From a theoretical point of view, the fundamental level of real rates is determined by the balance between desired savings and desired investment. The savings-investment mix is influenced by marginal productivity of capital, rates of time preference, expected after-tax income, and demographic factors. Real short-term rates are also influenced by the non-inflationary long-term potential growth rate of an economy, which is positively correlated with productivity and is affected by demographics.

Moving from the short-term anchor out along the yield curve, longer-term interest rates are based on current short-term rates plus a variety of risk premia. There is a premium for **inflation risk** (the possibility that inflation will be higher in the future that will erode purchasing power of the interest and principal of the bonds); **term risk** (the uncertainty about future interest rate changes that will impact the worth of the coupon payments of the bonds); **liquidity risk** (the risk of difficulty selling the fixed income product in the future); and **credit risk** (the risk of default).

When short-term rates are at their neutral level, the various risk premia traditionally result in rising yields on longer term instruments, with the result of a positively, or 'normal', sloped yield curve. However, during periods when monetary policy is particularly restrictive, there can be occurrences of inverted yield curves when short-term rates are higher than long-term rates.

The volatility in long-term rates is associated with alterations in monetary policy, changing market expectations and fluctuating assessments of the various risks. It is worth noting that if capital was perfectly mobile, the equilibrium interest rates would be set in global markets at a world level varying by term. In practice, capital mobility is not perfect and differences in national interest rates do occur. For example, national interest rates can differ significantly if financial markets expect changes in real exchange rates, which will impact the returns that investors receive. Portfolio preferences of various investors can also have an impact by influencing the required various risk premia in national markets. Fiscal balances can influence the presence of a national risk premia, with large deficits lifting term, default and inflation premia.

and 1990s was simply the product of lower inflation, which fell from a double digit rate at the start of the 1980s to an average of 2.5% in the U.S. and an average of 2% in Canada since the mid-90s. This reflected the successful efforts by monetary authorities to reduce inflation and anchor inflation expectations at sustained low levels.

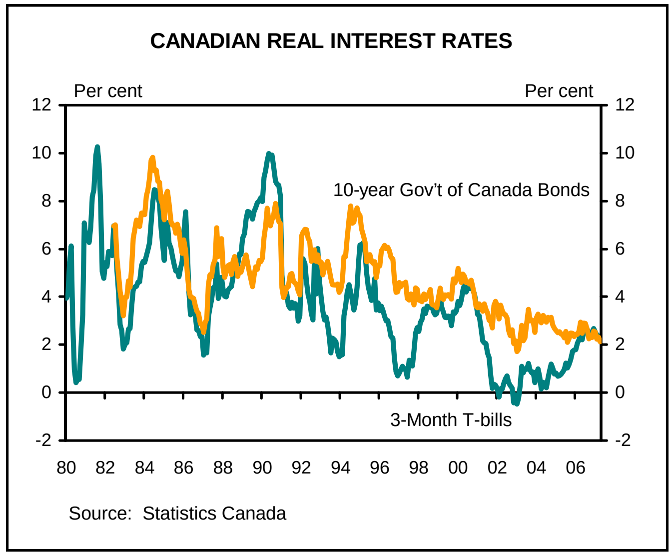
However, there is more to the story than just slowing inflation, as there has been a steady decline in real (after-inflation) interest rates as well. Real long-term U.S. yields – 10-year bonds yields less inflation based on the year-over-year change in the core CPI – went from 8.4% in mid-1984 to an average of 3.3% in the final two years of the 1990s. The real long-term benchmark Canadian bond yield dropped from 8.5% in 1984 to 4.2% in 1999.

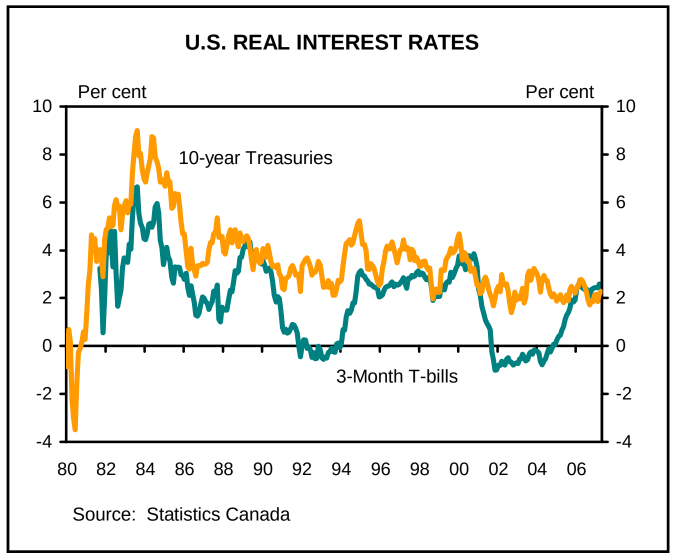
Several factors appear to have contributed to the dramatic decline in real long-term rates. First, as shown in the accompanying charts, there was a secular drop in real short-term rates. Similar to the inflation experience, the efforts and increasing credibility of the central banks (including their improved transparency) were the main catalyst for the change in real short-term rates.

The second factor pushing long-term rates lower was a decline in the various risk premia required by investors. Fixed income markets experienced a virtuous circle. The inflation premium fell as markets became confident that the days of high and volatile inflation were in the past. This led to lower and more subdued movements in short-term rates, which also curtailed the term risk premium. As this led to lower and less volatile bond yields, the greater stability of fixed income markets in general contributed to the declining path in yields. The disinflationary trend and the greater stability in interest rates resulted in a more subdued and stable pace of nominal GDP growth. Since nominal GDP is ultimately the source of income from which interest is paid, the trend also contributed to the declining level of interest rates. The lower volatility in economic growth and income also helped to constrain the swings in interest rates that, in turn, tempered risk premia.

Federal governments in both the U.S. and Canada also started to run significant budget surpluses in the second half of the 1990s and experienced declining debt (as a percentage share of GDP and in absolute terms), which added to the attraction of their bonds and helped to lower yields.

It is difficult to empirically observe the decline in the risk premia. Over the 1990s, the spread between real long-term rates and real short-term rates narrowed. However,





the difference in real yields soared in the early part of this decade, but this was due to the aggressive easing in monetary policy following the tech wreck and equity correction at the start of this decade. In other words, the reason the spread increased was due to market expectations that the abnormal low levels of short-term rates would not be sustained indefinitely. The difference in yields then narrowed dramatically when the central banks normalized monetary policy.

For an alternative approach to illustrating the decline in the risk premia, we can subtract an implicit assumption about the 'neutral' (i.e. long-term equilibrium level) of short-term rates from the real long-term bond yields. In recent years, many economic papers and analysis (including the Taylor rule for the conduct of monetary policy) have assumed a neutral real fed funds rate of 2%. In the accompanying chart, we show the extent to which U.S. long-term real bond yields have trended lower relative to this 2% neutral level of real short rates.

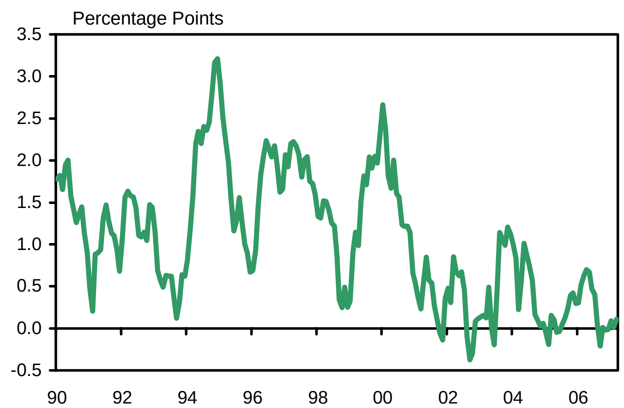
Even lower rates in the 2Ks

Interest rates continued to decline in the U.S. and Canada in the early part of the decade. However, a case could be made that the adjustment to the low and stable inflation environment should have been complete by the end of the 1990s. If one looks at the spread between yields on nominal bonds and real return bonds, it is evident that financial market inflation expectations had become well anchored by the end of the last decade. Nevertheless, real interest rates dropped further due to the influence of a number of factors.

Short-term rates fell in the wake of the 2001 tech bubble collapse and a mild U.S. recession. In fact, the central banks were particularly aggressive in easing monetary policy, with the Fed funds rate being lowered to a mere 1.00% and the Bank of Canada overnight rate being reduced to a less extreme 2.25%. However, these cyclically low cash rates were eventually reversed, with fed funds moving to a slightly restrictive 5.25% and the overnight rate returning to 4.25%.

The real surprise was the ability of long-term bond yields to stay low even when the central banks tightened monetary policy, which is often remarked upon as "Greenspan's conundrum". While the Fed was hiking short-term rates from a low of 1.00% in May 2004 to 5.25% in June 2006, the yield on 10-year Treasuries only climbed from 4.66% to 5.15%. In other words, short-term rates increased 425 basis points, but long-term rates nudged upwards by a mere 49 basis points. In the second half of 2006 and early 2007, 10-year yields gave up their prior increase, falling to 4.56% in February, but then returned to 5.11% in mid-June 2007. At the moment, fixed income markets are fixated on the latest rise in yields, but the reality is that the level of long-term interest rates is still consistent with the 'conundrum'.

U.S. LONG-TERM REAL RATES LESS NEUTRAL REAL SHORT-TERM RATES



Source: Haver Analytics, U.S. Federal Reserve

Key Factors Contributing To Low Bond Yields

1. Lower inflation reduced nominal interest rates across the yield curve
2. More stable inflation and economic growth reduced inflation and term risk premia
3. Supply and demand factors created downward pressure on yields. Factors included:
   - Global savings glut
   - Oil shock
   - Demographics and pension demand
   - Corporate saving

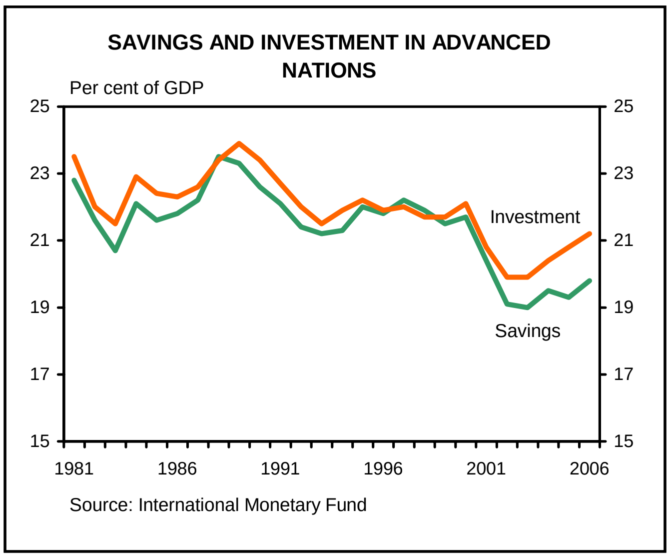
A host of explanations have been offered for the lack of response in bond yields. The most obvious is that during a time of slower economic growth, fixed income markets simply anticipated that inflation would eventually diminish and this would lead to lower short-term rates in the future. However, the cyclical explanation cannot fully explain the failure of tighter monetary policy to boost yields on long duration bonds. This has led to a number of other theories, with the most popular being the presence of a major global savings imbalance.

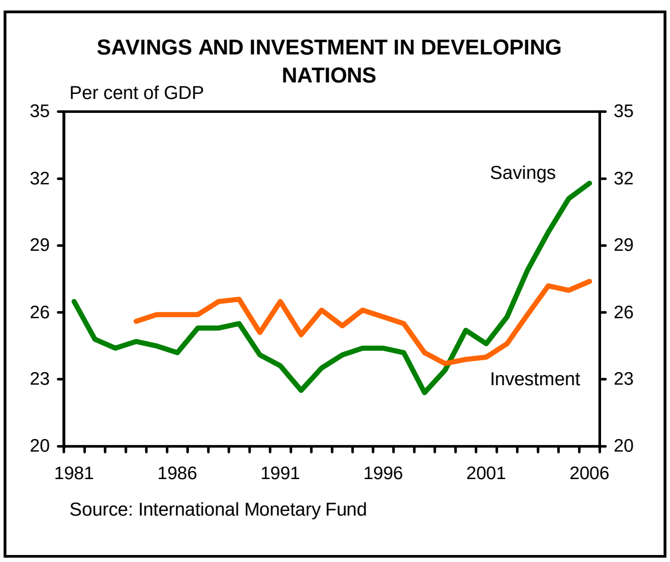
Global savings glut

At the most basic level, interest rates are the price of borrowing from savings to make investment. In other words, interest rates equilibrate desired savings with desired investment. In recent years, the pool of global savings has exceeded the desired amount of investment, which has put downward pressure on interest rates around the globe.

Within the industrial world there has been an increase in corporate saving due to rising profitability that reflected the shift to global production and greater access to new low cost labour centres. However, this was more than offset by reduced household saving and – outside of Canada

– significant government deficits. At the same time, with slowly growing workforces and high capital-labour ratios, many industrial countries recorded modest growth in investment, particularly for business capital outlays. The net effect was that even with meagre gains in investment, the constrained savings led to the development of current account deficits in many industrialized countries, particularly the United States and to a lesser extent France, Italy, Spain, Australia, and the UK. Japan and Germany were key exceptions, which in the case of the former is the product of Japan's high savings rate and in the case of the latter has reflected the weak state of the German domestic economy until just recently. Canada's current account surplus also recorded an increase, but this came in the context of the commodity price boom and significant government saving, which added to corporate saving that puzzlingly has not fuelled robust business investment.





While the industrialized world has been generally dissaving, the developing world has experienced a sharp increase in savings at a time of subdued investment. The result has been significant flows of credit from emerging market economies to the industrialized world.

This trend may be partially the legacy of the numerous financial crises that have occurred over the past 13 years, including: Mexico in 1994, East Asia in 1997-98, Russian in 1998, Brazil in 1999, and Argentina in 2002. The financial crises tended to lower investment due to the capital overhang from the prior boom, the resulting weak corporate balance sheets, and the high levels of non-performing loans. The fallout from the financial crises also tended to create a period of protracted weakness in domestic demand that lowered investment.

The experience and lessons from these financial problems motivated many emerging countries to better manage their international capital flows, leading them to shift from being net importers of financial capital to being net exporters. This produced growing current account surpluses and the accumulation of large foreign exchange reserves. In other words, the countries became significant savers.

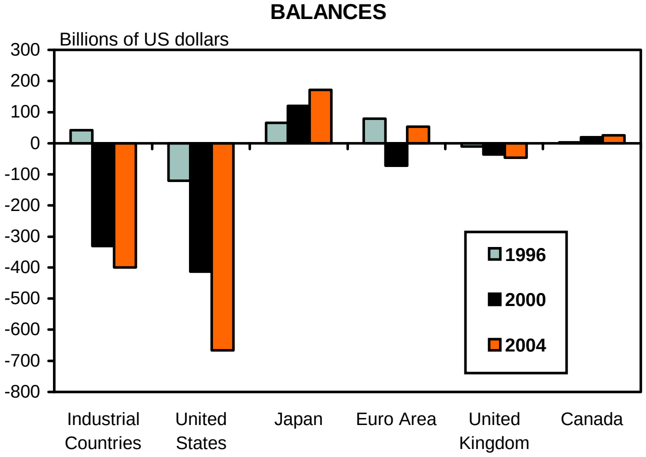
At the same time, more emerging market economies began to put greater weight on export-led economic growth in an effort to replicate the past successes of some newly industrialized nations. These efforts boosted foreign exchange reserves and pushed current account surpluses even higher. Moreover, there was a focus on reducing the burden of external debt by attempting to pay down those obligations, which was achieved through reduced fiscal deficits, which again contributed to current account surpluses, reduced the overall supply of debt in international markets and led to lower yields.

China has been a key exception to the weak investment performance by developing countries. Indeed, China has experienced explosive investment expansion. However, savings have still exceeded investment, with the result that the country has recorded a ballooning current account surplus and a dramatic increase in foreign exchange reserves. The high savings rate is partly explained by the poor social safety net and the limited access of households to credit at a time of great economic change.

The oil price spike in the early part of this decade also contributed to a sharp increase in saving among the major oil exporting countries, the majority of which are found in the developing world. This is a traditional occurrence when there is a considerable run up in energy prices, as the oil-endowed countries often view the initial increase in prices as temporary and they are slow to deploy the funds for business investment or other purposes. The result is a sharp increase in saving, widening current account surpluses and dramatic foreign exchange reserve accumulation.

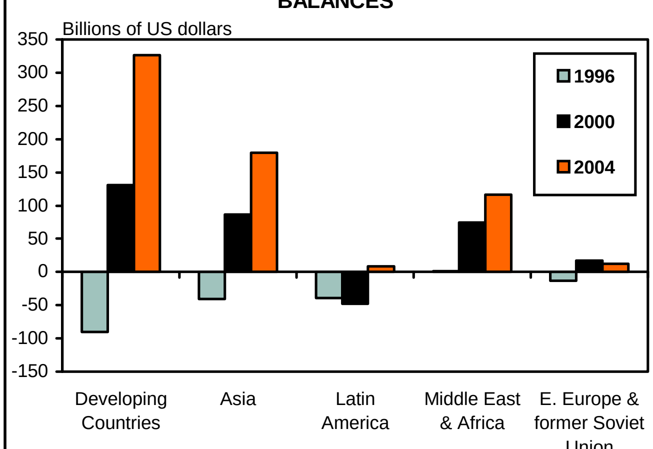
The net result of all of these trends was excessive global savings, a large part of which has flowed into bonds in the developed world, particularly in the United States, and acted to dampen global long-term interest rates even when monetary policies in many jurisdictions have been tightened. This trend has allowed the U.S. to finance its massive current account deficit and explains the dramatic accumulation of U.S. dollar foreign exchange reserves in Asia and by the OPEC nations.

DEVELOPED COUNTRY CURRENT ACCOUNT BALANCES



Source: Federal Reserve

DEVELOPING REGION CURRENT ACCOUNT BALANCES



Source: Federal Reserve

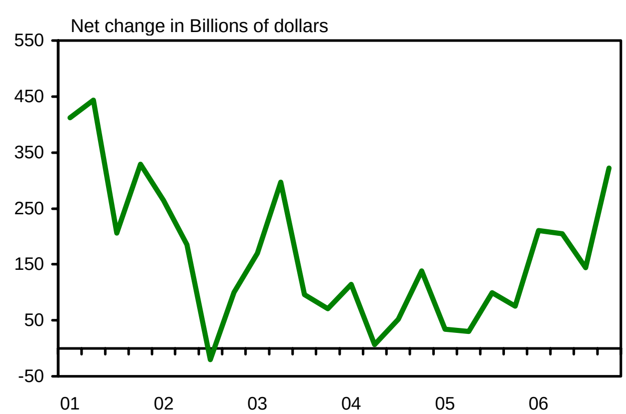
Strong pension demand for long-term debt

Another factor cited as constraining long-term interest rates is increased demand for long-term debt by pension funds. In the wake of the 2001 tech wreck, pension funds were squeezed by two forces. The equity market correction reduced the assets of many pension funds, while falling interest rates boosted the calculations of the discounted present value of the future liabilities. The resulting funding gap subsequently led some pension funds to pay more attention to the asset mix of their portfolios and there was a greater push to match the duration of assets and liabilities. This boosted demand for bonds from the pension fund sector, creating downward pressure on yields.

The impact of robust corporate balance sheets

Shifting from the demand side of the equation to the supply side, the increase in corporate saving in the industrial world may have also helped to limit the rise in long-term government bond yields. As already mentioned, corporate profits have soared since 2001. This reflected the cyclical economic recovery from the 2001 slump, but it was also the product of tapping low cost labour centres in Asia and Eastern Europe, the disinflationary impact of exports from these regions that boosted the profits of importers, and the conservative capital outlays by corporations. All of this led to a sharp improvement in corporate balance sheets from 2001 to 2005, with assets rising and liabilities being reduced. The resulting increase in corporate liquidity diminished the need to issue debt over the early years of this decade, limiting new supply to markets and likely boosting demand for government debt, despite low yields.

U.S. CORPORATE BOND LIABILITIES



Source: U.S. Federal Reserve

Where do rates go from here?

We have outlined how and why interest rates have fallen so dramatically over the past several decades. Attention will now turn to the issue of where yields are headed from here. There are a variety of approaches to tackle this question. First, one can look at history for a guide. Second, we can consider if there is a natural anchor to yields from a fundamental point of view and how that anchor might change in the future. Third, we can look at each of the major factors that have been impacting fixed income markets and consider how they might change.

History suggests low and flat yield curves are normal

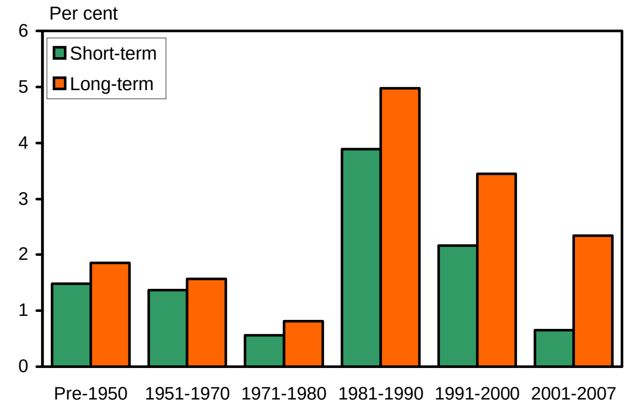
Economists are generally uncomfortable with statements suggesting that 'it is different this time around'. It is rarely a brave new world and history does have a tendency of repeating itself, although the parallels are never exactly the same. There is no question that interest rates have been on a declining path over the last three decades, but a longer time perspective suggests that the increase in rates in the 1970s and the subsequent drop in 1980s and the first half of the 1990s were the aberration.

The average U.S. inflation rate from the 1850s to 1970 was roughly 2.5%, similar to the experience over the last decade. Real U.S. short-term interest rates averaged close to 1.5% and real long-term yields averaged 1.7% between 1850 and 1970, implying that nominal yields of close to 4% are not abnormal and the average level of yields corresponds to an extremely flat yield curve.

Some may be uncomfortable going back as far as the U.S. Civil War. As an alternative, one can look at the experience during the 1950s and 1960s, a period of strong economic growth and a subdued low inflation rate that averaged 2% over the two decades. During this period, nominal U.S. short-term rates averaged 3.6% and long-term rates averaged 3.9%, resulting in real yields modestly below 2%. Again, while the slope of the yield curve fluctuated significantly over the years, the slope based on the average level of yields was remarkably flat.

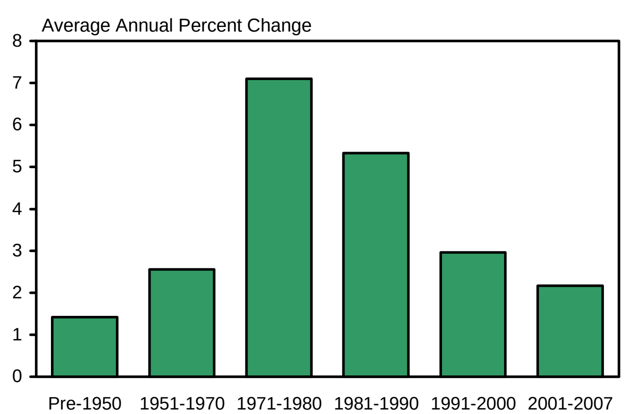
We can also look at the performance of Canadian fixed income products in the 1950s and 1960s, a period in Canada with subdued inflation averaging roughly 2.5% and with comparative fiscal stability. During this timespan, the Bank Rate averaged 3.71%, while nominal yields for bonds of 10-years and longer duration averaged 4.67%. Removing the trend rate of inflation, the real level of yields was a mere 121 basis points for cash and 2.17% for long bonds.

U.S. REAL INTEREST RATES



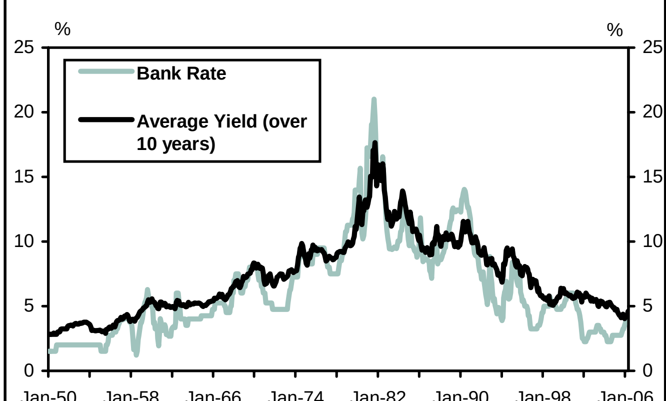
Source: U.S. Federal Reserve

U.S. INFLATION



Source: U.S. Federal Reserve

BANK OF CANADA BANK RATE AND AVERAGE BOND YIELDS OVER 10 YEARS



Last plotted: April 2006; Source: Statistics Canada

All of this implies that the recent level of interest rates is far from unique and a historical case could be made that yields could trend lower.

The period of low and stable inflation expectations

An alternative approach is to look at the experience since inflation expectations became well anchored in the mid-1990s. Since 1996, the average rate of U.S. inflation as measured by the CPI has been 2.6%, while core CPI has averaged 2.3%. This fits well with the commonly accepted view that the Fed's tolerance range is 2.0 to 2.5% on this measure. In Canada, headline inflation has averaged 2.0% from January 1996 until April 2007 – bang on the Bank's 2% target.

Given the success of the central banks, one might argue that interest rates over this 11-year period might also provide a guide to the future. In the United States, real short-term rates averaged 1.56% and real 10-year Treasuries averaged 2.87%, resulting in nominal yields of 4.16% and 5.47%, respectively. Canadian real 3-month T-bills averaged 1.94% and 10-year bond yields averaged 3.55%, or nominal rates of 3.94% and 5.55%.

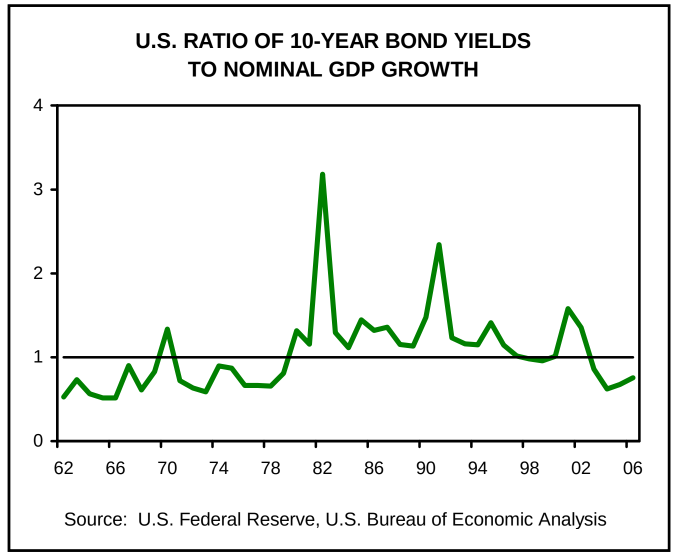
It is interesting to note that the average yields correspond to a fairly steep yield curve in both countries, but this was largely due to significant changes in short-term rates and not major swings in long-term rates – a key theme that we will return to a bit later.

Traditional anchors to interest rates

Theoretical anchors to the level of interest rates provide an alternative to using history as a guide.

At the short end of the yield curve, the 1996-2007 experience seems consistent with estimates of neutrality – a level of short-term interest rates that neither adds stimulus to the economy, nor applies the brakes. An OECD study[1] has suggested that the neutral real fed funds rate trended down to 2% in the early part of this decade from between 2% and 5% since the 1960s, while the euro-area neutral level has come down to around 1.5% to 2.0%.

Looking forward, economic theory suggests that the neutral level of rates may fall further and the impact would likely be felt across the entire yield curve. A Fed study[2] suggests that there is a 1:1 relationship between changes in potential real GDP growth and the neutral level of rates, which likely reflects the fact that a slower trend rate of economic growth also implies weaker demand for investment. If this relationship holds, the outlook for slowing



economic growth due to an aging population and a moderation in labour force growth implies that short-term rates could trend lower. The long-term sustainable (i.e. potential) rate of U.S. economic growth is projected to fall from the current 3.2% to 2.6% in 2020. This could lower the neutral real fed funds rate by 60 basis points from 2% to 1.4% and, assuming no change in central bank inflation tolerance level of between 2.0 and 2.5%, would lead to a nominal neutral of 3.4 to 3.9%.

TD Economics has traditionally assumed a neutral short-term rate in Canada of roughly 2.5%, or a nominal 4.5%. The 50 basis point spread over the 2% assumption of neutral U.S. real rates was a country risk premium that Canada has historically required. Looking ahead, we don't believe that this risk premium is warranted, given the country's superior fiscal position and economic fundamentals, which would lower the neutral level to 2%. Demographics suggests that the potential pace of economic growth in Canada will slow from an aging population, dropping from 2.8% to 2.2% in 2020, or 60 basis points. By this reasoning, the neutral level of Canadian real short-term rates should fall to 1.4% or a nominal level of 3.4%, assuming 2% inflation.

Moving out to the other end of the yield curve, bond yields tend to be anchored by the pace of nominal GDP growth over the long haul. This relationship is based on the fact that the growth in income in the economy is ultimately the source of demand for funds and the source of payments of interest. Although the assumption is weak in the short-term, the accompanying chart does appear to suggest that bond yields do revert towards the pace of nominal GDP growth eventually over time. If this relationship holds, the aging of the population will likely knock 60 basis points off of nominal GDP growth in the U.S. and Canada. This would lower nominal GDP growth to 4.6% in U.S. and 4.2% in Canada – implying a similar level of long-term bond yields.

The outlook for recent forces impacting markets

The final approach to projecting the outlook for interest rates is to discuss how the factors that have recently been impacting fixed income markets might change and consider other possible factors that could come into play.

Low and stable inflation/economic growth to persist

Inflation is likely to remain low and stable in the years ahead. It is difficult to imagine that the monetary authorities are going to give up the credibility they have struggled so hard to obtain. In the case of Canada, there is a possibility that inflation might even be lowered. The Bank is currently investigating whether an inflation target of less than 2% would generate significant net economic benefits[3]. At this point, the Bank's intent is only to raise the issue for discussion and study. However, if the change did occur, there is every reason to believe that the Bank would be successful in meeting the lower target, which would reduce interest rates in Canada across the entire yield curve once the new lower inflation expectations become anchored.

If inflation remains subdued, market expectations that interest rates will remain low and stable are unlikely to be challenged. Similarly, the reduced volatility in economic growth should also persist. As a result, the more modest swings in interest rates associated with the period since the mid-1990s is likely to be maintained.

Unwinding of global savings to create upward pressure on yields

The same cannot be said of the global savings glut. The tide will turn at some point, but the timing is impossible to predict with any precision. The current situation makes little sense from the perspective of economic theory. With their younger and more rapidly growing workforces, the developing world should be experiencing lower savings rates. Part of the current explanation for the savings behaviour may be the limited social safety net available in many countries. However, these should be developed with time, allowing savings rates to decline. Financial system reforms and increasing access to credit in the future may also reduce the savings rates in the developing world.

At the same time, given their relatively low ratios of capital to labour, emerging markets should be able to provide greater returns to capital than those available in the developed world and this should fuel stronger investment in emerging markets.

With time, the oil exporting nations should also start to deploy a greater portion of their savings. After all, there is an implicit economic cost to the accumulation of foreign exchange reserves, since the funds could be deployed to more productive uses.

It is inevitable that some foreign exchange adjustment will eventually occur globally, which will only help to stem the rapid accumulation of foreign exchange reserves by developing countries. Meanwhile, the demographics of aging population should lead industrial countries to save more.

A number of studies have tackled the impact of the recent global savings glut on U.S. Treasuries. An OECD paper[4] suggests that U.S. Treasury yields would increase by almost 1 percentage point if Asian capital inflows returned to more traditional levels. An NBER paper[5] concludes that without the foreign government capital inflows over the 12 months ending in May 2005 the yield on the 10-year Treasury would have been 90 basis points higher. The U.S. yield curve between 2-year and 10-year Treasury yields would also have been 52 basis points steeper.

These results are particularly interesting since they imply that the U.S. yield curve would have been positively sloped in recent years were in not for the global savings glut.

Although Canada is unlikely to be directly affected by the unwinding of the global savings imbalance, there is still likely to be a significant indirect effect. Fundamentally, Canadian fixed income products trade as spread products off of their U.S. counterparts that have become an international benchmark. Any increase in U.S. yields due to reduced foreign demand would represent an upward shift in the level of world interest rates and that would exert some upward pressure on Canadian yields.

Impact of demographic forces are ambiguous

The outlook for the influence of demographics on fixed income markets is far more problematic and its impact is far more ambiguous.

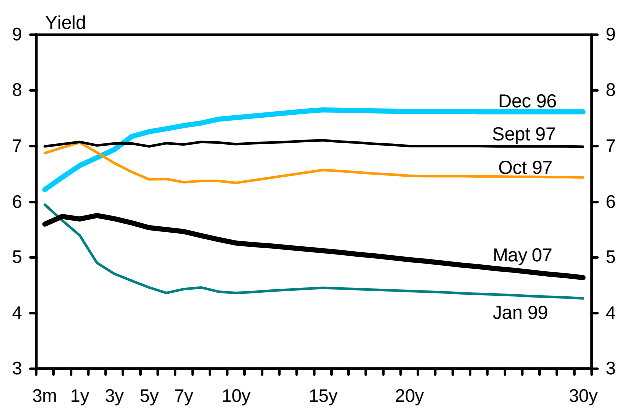
Pension demand could depress and distort yield curve

There is every reason to expect that pension fund demand for adequately yielding debt will remain robust and might even intensify. Pension assets will continue to accumulate and the pressure will remain to match duration of assets to that of liabilities. This could have a significant depressing impact on bond yields, particularly if there is any sudden change in the asset mix of pension funds towards fixed income. To illustrate, a Morgan Stanley report[6] noted that under a specific set of assumptions an abrupt change in pension holdings of U.S. bonds "would temporarily reduce equity prices by 10-15% and flatten the yield curve by 75-150 basis points" while "a gradual rebalancing could temporarily reduce equity prices by 8-12% and flatten the yield curve by 35-60 basis points in the first few months following the implementation."

There is also a good illustration from the U.K. experience over the past decade of how a sudden and significant change in pension asset holdings towards bonds can really distort a yield curve over a lengthy period of time. In the mid-90s, the U.K. government established the Minimum Funding Requirement (MFR). This was a stringent capital requirement which required that pension fund liabilities be 100% funded. If the pension fund falls below this level the deficit must be remedied within five years. In the case of falling below 90%, this deficit must be remedied within one year.

The impact of the MFR was dramatic. The U.K. government yield curve flattened sharply, with the spread between 30-year bonds and 3-month T-bills dropping from about 135 basis points in January 1997 to zero across the entire curve by September 1997. In October 1997, the yield curve started to develop a negative slope and it has remained inverted in some form ever since. At times the

U.K. GOVERNMENT BOND YIELDS



Source: Bloomberg

inversion has exceeded 200bps across the curve, such as in 1999, and currently the inversion is around 100 basis points.

So, it is possible that strong pension demand could constrain U.S. and Canadian bond yields and, at the extreme, they might even cause periods when the yield curve is inverted, or at least times when segments are inverted.

Demand for bonds may increase from older investors

Adding to the demographic pressures of strong demand for bonds from pension funds is speculation that the older individuals across the industrial world might also shift their asset allocation in favor of bonds. This is a traditional financial planning recommendation based on the fact that older investors have less risk tolerance and greater demand for steady income flows from their investments.

Impact of demographics could prove limited

However, there are a couple of factors that might offset the downward pressure on yields from the rising demand by pension funds and investors. First, demand is affected by the level of yields. Yes, pension funds and investors could depress the returns from bonds, but at some point the attraction of fixed income products would be eroded to the point that investor demand drops.

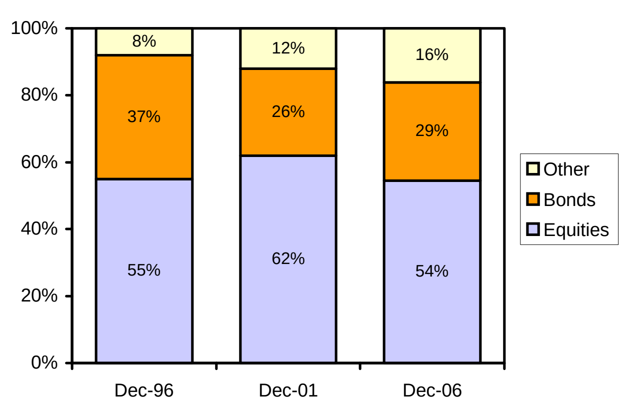
Consider the current rate environment. If an individual bought a 10-year Government of Canada bond in late May 2007, they earned a yield of 4.30%. Assuming the combined Federal-Provincial top marginal tax rate of 46% in Ontario, the after-tax yield is only 2.32%. Taking off the Bank's inflation target of 2%, the after-tax, after-inflation return is almost zero, and might be negative after fees. The implication is that bonds are only providing capital preservation. While that may be acceptable to some older investors, it is unlikely to be appealing to the vast majority. This implies that other income yielding investments will be more attractive, such as high dividend paying stocks that receive a more favourable tax treatment and provide the added attraction of potential capital gains.

As demand for income generating financial assets increases, it is also reasonable to expect that financial markets will respond with the creation of new financial assets to meet the needs, and these products would act as substitutes to bonds. One also shouldn't underestimate the increase in investor knowledge and sophistication. Although prior generations were strong proponents of fixed income products, like GICs, the current generation is increasingly savy equity investors.

The tax exemption of pension funds means that they will receive a greater return than individual investors, but it may still prove inadequate. Most pension funds appear to aim for returns in the high single digits, while bonds will likely provide in the low to mid single digits. This is likely to dampen demand and, even in the current interest rate environment, we can already see this happening. According to a 2007 study by Watson Wyatt Worldwide[7], the global pension asset allocation to bonds has fallen from 36.5% in 1996 to 31.5% in 2001 and to an estimated 25.5% in 2006. Over this time span, pension funds in the U.S. lowered their allocation from 33% to 21%, while in Canada they fell from 37% to 29%. Although the equity allocation has increased over the ten year period, the greatest shift has been an increase in the 'other' category, which is a reflection of the move to alternative investments that could provide a steady income stream that was significantly higher than bonds.

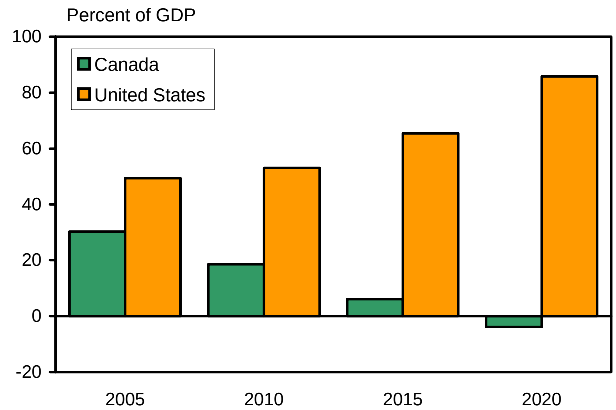
It is also unreasonable to expect a sudden shift in the asset allocation to bonds, as pension funds are very cognizant that this would depress yields. Any change in the asset mix is likely to occur over a multi-year period. It is interesting to note that the same Morgan Stanley report that highlighted how a dramatic change in asset mix could have a major impact on yields also stressed that, "If the reallocation and duration extension were phased over a multi-year period, the market impact of even such a large portfolio rebalancing move … likely would be swamped by more fundamental factors, such as inflation, growth, and monetary policy. The so-called 'technical' factors of supply and demand typically magnify, but do not overwhelm, those fundamentals"[8].

CANADIAN PENSION FUND ASSET ALLOCATION



Source: Watson Wyatt Worldwide

NET GOVERNMENT DEBT
(BASE CASE STATUS QUO PROJECTION)



Source: Standard & Poors

Finally, a strong case can be made that pension funds will have to lower their financial return targets in the future, since high single digit performance will likely be unattainable, but the outlook is still that bonds will provide meagre returns that fall short of the pension fund objectives.

Global bond supply may also surprise on the upside

The pension and household demand for debt is also only one side of the demographic equation. There is a general perception that given the large scale assets of pension funds, which exceed the total outstanding issuance of debt by the G10 industrialized nations, there may not be enough supply of government bonds in the future to meet demand. In the case of the Canadian fixed income market, this position has a lot of appeal. The federal government is consistently running budgetary surpluses, reducing the need to issue long-term debt at the same time that domestic pension funds have an almost insatiable appetite. And, it is worth noting that even if the pension asset allocation of bonds is falling, this could still depress yields if the absolute total demand still exceeds available supply.

However, the outlook changes when one moves from the Canadian market to the global market. There does not appear to be adequate attention to the fiscal pressures that are likely to come from the aging population across the industrialized world. In 2006, Standard & Poors released a series of reports on the impact of demographic changes and the potential implication on sovereign credit ratings[9]. The results were shocking.

In the status quo base case, where the governments meet all of their current public policy commitments on health care and social security, U.S. net debt soars from 49.2% in 2005 to 85.8 % of GDP in 2020. The U.S. general government balance deteriorates from a deficit of 3.9% of GDP in 2005 to 9% of GDP in 2020. The outcomes for Japan and Europe are far worse.

In truth, the S&P base case projections are extreme. The credit rating on U.S. Treasuries drops to BBB status by 2020. Obviously, the U.S. government would not allow this to occur. Benefits would be scaled back, taxes would be increased, or other government expenditures would be reduced. However, all of these solutions are extremely painful. This leads to the conclusion that while something will give, the odds still favour a significant increase in government deficits and government debt issuance.

Just to give a flavour of the impact that could occur, a U.S. Federal Reserve report by Thomas Laubach estimates that a 1 percentage point increase in the deficit-to-GDP ratio raises long-term interest rates by 25 basis point[10]. The implication is that a significant fiscal deterioration could boost long-term yields by more than a full percentage point and if governments in the U.S., Europe and Japan were all in the same boat, the impact would be to lift the world level of long-term interest rates.

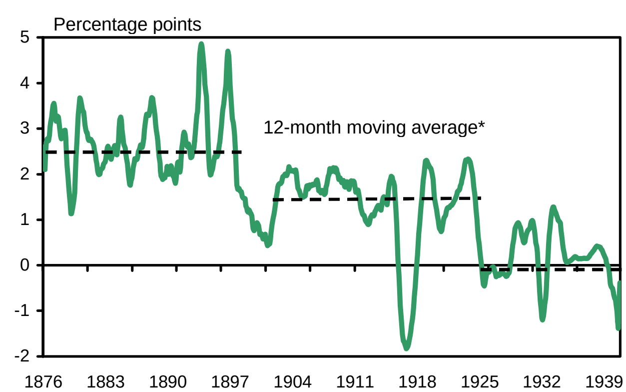
This also raises a fundamental question about the outlook to inflation and the conduct of monetary policy. In an earlier section, we stressed that the monetary authorities are unlikely to give up their credibility as inflation fighters. However, their resolve could be tested. Governments with excessive spending can elect to reduce the cost of financing their fiscal burden by allowing a higher rate of inflation. In our opinion, the risk of this happening is low. The central banks in the industrialized world have a considerable amount of independence and they all recognize that the best policy objective they can pursue is price stability, which was the primary lesson learnt during the 1970s and 1980s experience. Nevertheless, one needs to acknowledge the risks that fiscal pressures could challenge the maintenance of the prevailing low inflation period.

It is interesting to note that Canada does remarkably well under the S&P base case projection. The Canadian general government balance remains at a 2% of GDP surplus to 2020 and net general government debt drops from 30.2% of GDP to -3.9% by 2020. This reflects the fully funded state of the Canadian Pension Plan and the solid condition of federal and provincial fiscal balances that are expected to cope with the future health care expenses. The implication is that Canadian pension fund demand for bonds may significantly exceed government supply, which, all else equal, would likely depress yields going forward.

However, everything else is not equal. Canadian fixed income markets would be impacted by any rise in world interest rates. It is also possible that there would be a supply response by corporations and foreign issuers. In the case of the former, debt financing could become more attractive to business. In the case of the latter, more foreign debt issuers could tap the Canadian market directly. In other words, the Maple bond market in Canada might experience dramatic growth. Finally, if Canadian yields were depressed significantly relative to foreign yields, Canadian pension funds could elect to buy foreign bonds and hedge the currency risk. In other words, global supply and global yields could reduce, or fully offset, the excess demand for Canadian government bonds.

One final consideration is a specific risk to the U.S. treasury market. U.S. bonds have benefited from the status of the U.S. dollar as a reserve currency. However, on a projection of interest rates going out to 2020, one might wonder if the days of U.S. dollar dominance might recede to some extent. As illustrated in the accompanying chart, U.S. interest rates did fall significantly relative to U.K. rates as America surpassed the economic influence of the British Empire in the early part of the last century. Over the next two decades, it does not seem unreasonable that the economic might of the United States might be increasingly challenged by Asia or Europe, which would put up-

SPREAD OF U.S. OVER U.K. SHORT-TERM PAPER



* U.S. New York Commerical Paper Rates less London Discount Rates on 3-Month Bank Bills

Source: NBER

ward pressure on Treasury yields as global funds shifted to alternative reserve currencies.

Low and stable interest rate environment likely to stay

So, what conclusions can be reached about the long-term outlook for interest rates?

Based on historical experience and outlook for the traditional anchors to interest rates, our assessment is that the average level of real short-term rates in the U.S. should be in a range of 1.4% to 1.6% over the period of 2007 to 2020. 10-year Treasuries are expected to average real yields of 1.7% to 2.9%. In nominal terms, assuming the Fed remains comfortable with CPI inflation in a range of 2.0% to 2.5%, the average level of nominal cash rates would be 3.4% to 4.1%, while long-term rates would be 3.7% to 5.4%.

Many of the recent factors supporting the sustained low and stable U.S. interest rate environment are structural, but some will abate. The most likely scenario is that inflation will remain at a low single digit pace, but the level of yields will be impacted by any change in the Fed's inflation tolerance levels. At the moment, there are no signs that the Fed will alter their implicit inflation objectives, but the Fed could entertain a lower or higher path for inflation in the future.

An aging population, increased pension demand for long-term debt and greater savings as well as demand for fixed income products from older investors could all create some downward pressure on yields. However, there will be an offset from an eventual unwinding of the global saving glut and a waning of the petrodollar capital flows from the current oil shock, which would tend to raise yields. Corporations are also unlikely to remain net savers. The fiscal cost associated with health care and social security commitments may also raise federal debt issuance and yields, while a declining importance of the U.S. dollar as a reserve currency could also lift the long-term equilibrium level of long-term interest rates. As a result, the net effect of the factors are ambiguous.

In Canada, history and traditional anchors point to real short-term rates of 1.4% to 1.9% and real long-term rates of 2.2% to 3.6%. With a 2% inflation target, nominal rates would be 3.4% to 3.9% at the short end of the yield curve, and 4.2% to 5.6% at the long end. These outcomes are not materially different than those for the U.S., but the outlook for many of the recent factors impacting yields

OUTLOOK FOR U.S. AND CANADIAN INTEREST RATES: 2007-2020

Historical Real Interest Rates

	U.S.		Canada	
	Short Term	Long Term	Short Term	Long Term
1850s-1970	1.5	1.7	--	--
1950s-1960s	1.6	1.9	1.2	2.2
1996-current	1.6	2.9	1.9	3.6

Central Bank Inflation Tolerance Levels

	U.S.	Canada
Yr/Yr % Change in CPI	2.0-2.5	2.0

Implied Nominal Rates

	U.S.		Canada	
Historical Real + Inflation	3.5-4.1	3.7-5.4	2.2-3.9	3.3-5.6

Neutral Real Short-term rates

	U.S.	Canada
	Short Term	Short Term
Nominal Assumption	4.5	4.5
Implied Real Assumption	2.0	2.5
Ex. Canada country risk premim	--	-0.5
Less impact of aging pop	-0.6	-0.6
Real Short-term rates 2020	1.4	1.4
Nominal Short-term rates 2020	3.4-3.9	3.4

Long-term Nominal Bond Yields Anchored by Nominal GDP

	U.S.	Canada
	Long Term	Long Term
Expected trend rate 2020	4.6	4.2
Implied real long-term rates	2.6-2.1	2.2

Expected Range for Average Level of Yields 2007-2020

	U.S.		Canada	
	Short Term	Long Term	Short Term	Long Term
Real	1.4-1.6	1.7-2.9	1.4-1.9	2.2-3.6
Nominal	3.4-4.1	3.7-5.4	3.4-3.9	4.2-5.6

Source: TD Economics

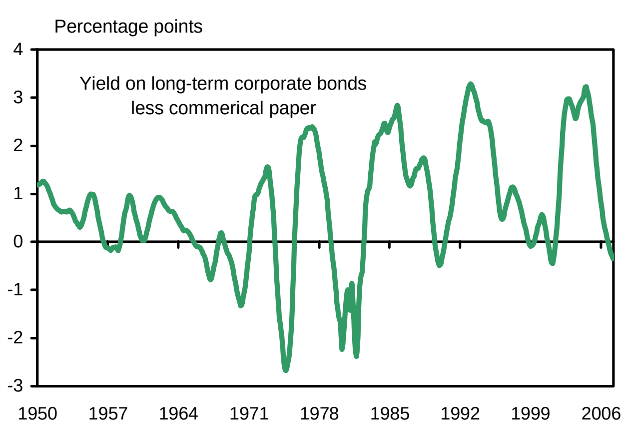
suggests that Canadian fixed income market will outperform. Negative Canada-U.S. interest rate spreads are likely to be the norm and the average slope to the Canadian yield curve is expected to be flatter.

It is not clear how the profile for inflation will impact Canadian fixed income markets. Although a higher inflation environment cannot be ruled out, it is clear that the odds favour a continuation of the current target, or a reduction to the inflation objective. Canadian fixed income markets would be indirectly affected if U.S. yields rise as the global savings glut unwinds or if demand for U.S. dollars wanes, but the increase in Canadian yields would be less – implying Canadian market outperformance. The fiscal pressure from an aging population should prove minimal in Canada, which is a positive for the relative outturn of Canadian debt products versus their U.S. peers. And, the demographic fallout from slower population growth and strong pension and personal demand should provide support to long-term Canadian debt, which is likely to experience less available supply than in the U.S. – pointing to a flatter yield curve in Canada.

It is possible that the Canadian yield curve could experience periods of inversion due to demographic demand and tight debt supply. However, as noted above, unless there is a new regulatory requirement imposed to hold a specific asset weighting in bonds, the distortion of the yield curve would likely prove temporary. The historical data suggests that the slope of the Canadian yield curve should be in the range of 20 to 150 basis points, but the top half of this outcome seems extremely high and we would anticipate that the average yield spread between 3-month T-bills and 10-year bonds will be 20 to 80 basis points.

Finally, although the average slope of the yield curves in Canada and the United States are likely to be relatively flat, business cycles will still occur and this will lead to periods when yield curve slopes become quite steep or inverted. Due to the sustained low and stable inflation environment, it is likely that the volatility in long-term yields will prove modest. Indeed, the change in the slope of the yield curve will be dominated by adjustments to monetary policy and to the resulting change in short-term rates. Since inflation is now anchored at relatively low levels, central banks have become very active in adjusting policy to small changes in inflation. This increasing importance of movements in short rates in driving yield curve changes has been evident in recent years and, unless central banks become less vigilant on inflation, this is likely to remain a dominant theme in the decades ahead.

U.S. INTEREST RATE SPREADS



Source: U.S. Federal Reserve

FACTORS IMPACTING FUTURE LEVEL OF INTEREST RATES

Factor	Direction of impact on yields: U.S.	Direction of impact on yields: Canada - U.S. Spread
Inflation	?	?
Global Savings Glut	▲	▼
Oil Shock	▲	▼
Aging Population	▼	No Change
Pension Demand and Private Saving	▼	No Change
Demographic Fiscal Pressures	▲	▼
Reduced importance of U.S. reserve currency	▲	▼
Assessment	**Ambiguous**	▼

Source: TD Economics

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ENDNOTES

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[8] Morgan Stanley, "Pension Missiles: Is the Cure Worse than the Disease?", Morgan Stanley, January 21, 2004.

[9] Standard&Poor's, "Global Graying: Aging Societies and Sovereign Ratings", Standard&Poor's, June 2006.

[10] Laubach, T., "New Evidence on the Interest Rate Effects of Budget Deficits and Debt", Board of Governors of the Federal Reserve System, May 2003.

The Fair Return Standard for Return on Investment by Canadian Gas Utilities:

Meaning, Application, Results, Implications

The Honourable John C. Major
Former Justice, Supreme Court of Canada

Roland Priddle
President, Roland Priddle Energy Consulting Inc.
Former Chair of the National Energy Board

March 2008

Acronyms and Abbreviations

AAM	Automatic adjustment mechanism
Alberta Board	Alberta Energy and Utilities Board
ATWACC	After-tax weighted average cost of capital
AUC	Alberta Utilities Commission
BC Commission	British Columbia Public Utilities Commission
BCUC	British Columbia Utilities Commission
California Commission	California Public Utilities Commission
CAPM	Capital asset pricing model
CE	Comparable earnings
CPUC	California Public Utilities Commission
DCF	Discounted cash flow
ERP	Equity risk premium
EUB	(Alberta) Energy and Utilities Board
FCA	Federal Court of Appeal
FRS	Fair return standard
LDC	Local distribution companies
Manitoba Commission	Manitoba Public Utilities Commission
MPUB	Manitoba Public Utilities Commission
MRP	Market risk premium
NGTL	NOVA Gas Transmission Ltd.
NEB	National Energy Board
NERA	National Economic Research Associates
Northwestern	*Northwestern Utilities Ltd v. Edmonton* [1929] S.C.R. 186
OEB, Ontario Board	Ontario Energy Board
Régie	Régie de l'énergie (du Québec)
RfD	Reasons for Decision
ROE	Rate of return on equity
SCC	Supreme Court of Canada
TCPL, TransCanada	TransCanada PipeLines Ltd
TQM	Gazoduc TransQuébec & Maritimes

Executive Summary

The meaning of the Fair Return Standard (FRS) Canadian governments responded to the growth of the gas business and the potential for abuse of dominant position in it by placing utilities under the jurisdiction of administrative tribunals. In theory, the extent of this regulation is unlimited. In practice it is constrained by the Constitution Act and by Common Law.

The Supreme Court in *Northwestern Utilities Ltd v. Edmonton* [1929] S.C.R. 186 (Northwestern) defined the scope of the utilities' right to price their product and their right as a result to a fair return. The Court stated "By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise". This definition remains in full legal effect today.

A fair rate of return to the corporation is paramount and is all that can be considered in arriving at a fair rate. In the unrealistic situation that a fair return worked a hardship on the consumer, the choices before government to provide relief are unlimited but they should not lower the fair rate of return. Indeed the Federal Court of Appeal (FCA) in *TransCanada PipeLines v. Canada National Energy Board* 2004 F.C.A. 149 confirmed that a fair return need not be modified out of deference to its impact upon customers.

As the operations of regulated utilities have become larger and more complicated, the courts have developed the view that a selected board of experts could deal more effectively with the rules of rate making than could the courts on appeal. Therefore, as long as the board in question acted within their jurisdiction, a successful appeal was unlikely. Notwithstanding the breadth of discretion afforded a regulator in establishing just and reasonable rates, the mutuality of interest between utilities and their customers nevertheless requires that a fair return be provided for the services rendered. The legal framework governing the determination of that fair return is the "Comparable Return Standard". It does not mandate any particular approach to that fair return.

The application of the FRS The current generic approach by Canadian regulators to gas utility rates of return on equity (ROE) awards pursuant to the FRS evolved after a long period in which regulators applied informed judgment to extensive evidence about a variety of tests. During that period, differing weights were given to the results but, with the exception of one jurisdiction and one test[1], none was ever permanently discarded. Over the years however, greatest reliance came to be placed on the equity risk premium (ERP) model.

With the passage of time, the phenomenon of successive protracted proceedings, eliciting similar evidence, stimulated the search for a generic approach. From the mid-1990's Canadian regulators accreted around the concept of an ROE for a benchmark utility based on an ERP over a risk-free rate, the resulting base-year award then being adjusted annually by a predetermined automatic mechanism. This is the essence of the generic ROE, now adopted for the regulation of that component of all major gas pipeline and distribution utilities' revenue requirements.

The results of regulators' current application of the FRS The number and duration of rate proceedings has been significantly reduced and in certain jurisdictions the way has been paved for long-term settlements, some of which have made provision for sharing of efficiency gains between customers and owners.

The Canadian approach to return matters stands in strong contrast to that in the USA, with which Canada shares the long tradition of cost of service utility regulation. There, in accordance with essentially similar jurisprudence, the fairness of return on investment is evaluated against the opportunity cost of capital.

While settlements are also common in the USA, American regulators have not pursued the generic ROE approach but instead maintain case by case reviews, emphasize the important role of informed judgment, entertain a variety of evidence, but tend to the discounted cash flow method (DCF) as the default mechanism for their fair return findings.

In the NEB generic ROE era, no new pipelines have applied for tolls based on that determination of ROE. Instead, new projects such as Alliance, Emera Brunswick, Maritimes and Northeast, and Mackenzie Valley have all come before the Board with negotiated tolls based on significantly higher ROEs. This suggests that the NEB's generic ROE is insufficient to attract capital to greenfield gas pipeline projects.

The implications of this application of the FRS The now-universal generic ROE approach by Canadian regulators of major gas utilities has created some regulatory economies. But unfortunately its mechanistic character suspends for lengthy periods the previously-valued application of informed judgment to the results of alternative methods of achieving the FRS required by Canadian jurisprudence in ROE awards.

A wide and unprecedented gap has developed between Canadian gas utility ROEs and those of USA utilities and of North American low risk industrials. This is factual ground for concluding that the FRS, essentially the opportunity cost of capital needed to ensure financial integrity and capital attraction, is no longer being achieved by the generic ROE approach.

Canadian regulatory convergence on the generic ROE may however inhibit its necessary reappraisal because particular regulators may be reluctant to break ranks with the group and because the consensus around an approved generic ROE is widely supported by stakeholders[2], for reasons of regulatory efficiency and short term economic self-interest.

It would be helpful if, at the same time as specific cases occasionally come before individual regulators[3], some further studies of general relevance were to be carried out. For example, examination is recommended of the results, *ex post*, of the generic approach in terms of the comparability of the resulting returns with non-utility and utility comparators and of the fundamentals of the present design including the choice of the risk-free rate; the appropriate measurement of the risk-premium; the adjustment mechanism; and the place of the DCF model which is accepted by the great majority of North American regulators.

Introduction

The Canadian Gas Association (CGA) Discussion Paper "Return on Equity: Allowed Returns for Canadian Gas Utilities"[4], highlighted the importance of a "fair return" in supporting investments for the long term strength of the nation's natural gas grid. The paper went on to summarize the origins and evolution of Canada's "fair return standard". The paper noted that Canadian gas utilities are not now receiving allowed returns comparable with those of U.S. gas utilities or low-risk unregulated companies. As a result, Canadian utilities, it stated, are treated unfairly and may be inhibited from offering a robust optimal system that would provide the highest quality of service today and would be properly oriented towards a sustainable energy future.

Against that background, the Association asked the present authors, who had provided advice in the drafting of the Discussion Paper, to expand on some of the issues raised in it, particularly the identified need for the policy community and regulators to ensure that allowed returns remain fair and appropriately reflect the significant changes in their foundational elements such as comparable earnings.

In response, the authors provide here an examination of the meaning of the FRS in jurisprudential terms, discuss its application by Canadian regulators over the decades, review the results of the convergence since the mid-1990s on a generic approach to returns on equity and consider the implications of that approach for the future health of Canada's gas utility businesses. As to the application of the FRS, regulators have received thousands of pages of evidence and written hundreds summarizing it, providing their views and setting out their reasons for decision. Our discussion is necessarily a selective and summary one. However, we hope not to have omitted any point of fundamental significance.

1. The Jurisprudential Meaning of the Fair Return Standard

The inception of utility regulation in Canada The introduction of utility regulation by governments was grounded in the view that the activity had evolved into a number of sufficiently large corporations operating in a business characterized by natural monopoly and therefore capable of exerting market power to the detriment of consumers.

History demonstrated a number of methods of control available to the authorities. In response to concerns about the monopoly power wielded by Standard Oil, the United States introduced anti-trust legislation which led to its massive restructuring into a number of smaller corporations, forcing increased competition. The result was re-organization of their position from virtual dominance of the sector to competition among the newly formed corporations. Similar experience occurred in diminishing the dominant areas in steel and railroads.

Canada, because of its size in terms of population and domestic product, chose to remove the actual or feared problem of monopolies in the utility field either by use of legislative regulation or by Crown ownership.

In the context of regulation, some economists express the view that a regulator serves as a surrogate for competition in terms of the regulated company's potential dominance of a particular activity. While this may not be a complete explanation of the public purpose, it is a useful analogy. The pertinent and difficult question is what should these regulated companies be entitled to charge their retail, commercial and industrial customers so as to ensure safe and modern service in exchange for a fair return on shareholders' capital?

Regulatory responsibility conferred on administrative tribunals The history of the natural gas industry is a relatively short one: it is only in the early part of the 20th century that independent commercial use started to visibly develop.

As privately-owned utilities started to evolve into fewer but larger companies capable of exerting market power, the response of Canadian governments was utility regulation under which administrative tribunals were given the jurisdiction to regulate private utility companies falling under their mandate. By and large, however, Crown-owned utilities were not regulated in the conventional way since their corporate governance was taken to be enlightened by the government's perception of the pubic interest of the day.

The recognition of the value of natural gas as a legitimate alternative to electricity and fuel oils as an energy source, and the need for such control, raised a number of regulatory and constitutional issues.

As a preliminary point, it is obvious that the constitutional division of powers dictated by sections 91 and 92 of the *British North America Act* divided the regulatory responsibility between the Federal and Provincial governments. This is a separate subject, capable of extensive comment, but it is sufficient for this paper to say intra-provincial activity fell to the Provincial Legislatures and extra-provincial activity to the Federal Parliament.

Constraints on the extent of regulation In Canada, the extent to which governments choose to regulate is theoretically unlimited. The absence of property rights for corporations makes them vulnerable to draconian legislation, if our governments so choose. However, the courts have recognized Common Law rights that co-exist with the Canadian Charter of Rights and Freedoms. Expropriation without compensation offends the Common Law rights of persons and corporations and is unknown to have occurred in Canada except for some unusual circumstances during war time.

The full reach and restraint by the Constitution Act or Common Law as they affect persons and corporations is beyond the narrower scope of this paper. It is sufficient to state that the rights are real, recognizable and enforceable.

Jurisprudence concerning utility rates—the fair return standard The important test of the prices or rates to be paid by consumers of natural gas supplied by a public utility has been established by our highest court, the Supreme Court of Canada (SCC). The Court confirmed the right of the companies to price the product within the confines of a fair rate of return on investments for the shareholder.

The SCC defined the scope of that right in 1929 and it remains in full legal effect today. It is consistently referred to and followed. The right to a fair return, and what it is, was defined by the SCC in *Northwestern Utilities Ltd. V. Edmonton,* [1929] S.C.R. 186 where Mr. Justice Lamont stated:

> "The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise".

The importance of maintaining safe and reliable service requires a fair return as defined by Mr. Justice Lamont. The consumer has grown accustomed to a high standard in the delivery of gas services. Humanly, they are used to both the high quality of product and service. Equally human, they balk at rate increases while knowing that to avoid deterioration in service, timely increases are necessary.

"Fair return" vs. fairness to the consumer While it has not yet happened, if providing a fair return to utilities as defined by the courts results in hardship for the consumer, how should it be resolved? The greater good is served by the application of Mr. Justice Lamont's definition. The language found in most legislation refers to words such as rate fair to the corporation and consumer. Fairness to the consumer in that sense is redundant. A fair rate of return to the corporation is paramount and is all that can be considered in arriving at a fair rate. The fair rate by logic alone should be deemed of necessity fair to the consumer.

That a fair rate of return would be a hardship on the consumer is practically unrealistic. It is academic and an unlikely result. An increase in rates is always unwelcome. If the rate rose to a hardship, some government intervention should be expected or the regulator may adjust the rate design while still ensuring the provision of a "fair return" to the utility. The point is that there are choices for relief, such as subsidies or a rate design short of lowering the fair rate of return. If hardship is the consequence of a fair return, nonetheless, the fair return must be set. Failure to do so over time will, as we have collectively seen, lead inevitably to the deterioration of, and in the extreme case, the failure of service and supply.

The Federal Court of Appeal (FCA) recently restated the principles of a fair return in *TransCanada PipeLines v. Canada National Energy Board* 2004 F.C.A. 149, where it confirmed the logic of Mr. Justice Lamont's definition by confirming that the fair return need not be modified out of deference to its impact upon customers. A fair return assures the opportunity to earn a level of profit equal to a comparable return from business of similar risk, although flexibility by which the ultimate tolls are designed may mitigate clear hardship or unfairness to consumers. However, by definition, a fair return should not result in these consequences.

Consumers and those outside the industry frequently forget or never considered that while utilities are by law always entitled to a fair return, it is a limited blessing in that higher earnings in buoyant times are not available to the utilities. There are no windfall profits such as may arise in other parts of the energy sector. It is only logical that the other side of that equation applies and a fair rate of return must also be allowed in less prosperous economic times.

Judicial review of regulatory awards The right to a fair return is one foundation of utility jurisprudence. Of concern is the growing development of the law that demonstrates a reluctance of the courts to review regulatory awards.

Until the 1930s, judicial review was more common as the courts viewed it their role to protect the public's interest. However, as Canada's industrial base grew and the operation of regulated utilities became both larger and more complicated, the view developed that a selected board of experts could deal more effectively with the rules of rate-making than the courts so long as the board in question acted within their jurisdiction, a successful appeal was unlikely.

The concept of judicial review was more elaborately defined by the SCC in *Pushpanathan v. Canada (Minister of Citizenship and Immigration),* [1998] 1 S.C.R. 982, where in summary it held that judicial review was identified by three tests. First, was the decision reasonable, second was the decision patently unreasonable and finally was the decision correct in law. It was only the latter, correct in law test, which receives a judicial welcome. It is the present law that a decision by the board must, if a question of law be correct any other finding or decision of the board must be patently unreasonable before judicial review is available.

The human concern by applicants of regulatory boards is the question of bias and fairness. A board that is neither can mouth the established fair return definition but not accept the applicant's facts. It is obvious that a fair return is dependant on the facts accepted by the Board and, except in extreme circumstances, the courts will not interfere. For fairness to occur dictates good faith by all participants.

Notwithstanding the breadth of the discretion afforded a regulator in establishing just and reasonable rates, the mutuality of interest between utilities and their customers nevertheless requires that a fair return be provided for the services rendered. The term just and reasonable does not displace the common law standard, rather it supports it (NWL 1929; TCPL 2004; see also *Ottawa Electric Railway Co. v. Nepean Township* (1920), 605 S.C.R. 216 at QL5, 11-12; *Chastain v. British Columbia Hydro and Power Authority* (1972), 32 D.L.R. (3d) 443 (C.C.S.C.) McIntyre J. at p. 454-456; *Re City of Dartmouth* [1976], N.S.J. No.457, 17 N.S.R. (2d) 425, MacKegan C.J. at QL para 11). As the Federal Court of Appeal most recently expressed it, failure to observe the fair return standard would result in tolls that are not just and reasonable. In some cases, the courts confirmed that the fair return need not be modified out of deference to its impact upon customers.

Conclusion Accordingly, it can be seen that the legal framework governing the determination of a fair return is the "Comparable Return Standard". It does not mandate any particular approach to the determination of a fair return. The courts have recognized the regulators' expertise in this area as superior to their own. What pervades the courts' approach to the determination of a fair return, however, is the mutuality of interest as amongst utilities and their customers in tying the availability of a fair return to the long term viability of the utility in providing the essential monopoly services our society requires.

The latitude given boards to set rates includes the ability to rely on a formula. It is unlikely that any one formula can fit all rates. A decision by a board that distorts fair return by the application of a formula that achieves that result poses the obvious risk of being incorrect at law and subject to judicial revision on that ground, a result any board would seek to avoid.

2. Application

The place given to the Lamont decision In their decisions on ROE[5], Canadian gas utility regulators[6] have seldom made explicit reference to the Lamont decision (Lamont). There have been important exceptions. Thus, in its seminal first decision on TransCanada's rates, the National Energy Board (NEB) in 1971 stated that it had been guided by relevant jurisprudence, as well as by its understanding of the [NEB] Act and then cited the "fair return" portion of the Lamont decision[7], followed by other now familiar cases, Canadian and American. Then, some 30 years later, in dealing with an application for review and variance of its 1995 decision on Cost of Capital[8], the Board noted that the applicant had cited Lamont and it went on to summarize the key elements of that decision, stating that in considering the legal framework associated with the determination of a fair return, the Board had looked at both prior judicial and Board consideration of the issue[9]. That 2002 decision was the subject of an application for review and variance and, in addressing the fair return standard, the Board in 2003 examined its legal obligations and again cited Lamont along with other Canadian and American jurisprudence[10]. Finally, in dealing in 2005 with an application for new tolls, the Board summarized the evidence and provided its views on the legal framework for determining a fair return, giving attention to Lamont and other cases[11]. The Alberta Energy and Utilities Board[12] (EUB, Alberta Board) in its landmark July 2004 decision on the Generic Cost of Capital, as part of its consideration of the legislative and judicial framework, examined relevant decisions, Canadian and American, starting with Lamont[13].

Lamont is present, whether explicitly so or not Despite the scarcity of specific references, it is nevertheless reasonable to assume that, while acting in accordance with their respective legislative mandates, all Canadian regulators in making ROE awards to gas utilities have recognized the jurisprudence relating to fair return, and specifically the Lamont decision, whether they have said so or not. In addition to the Lamont test of "comparable investment" or opportunity cost of capital, drawing on American jurisprudence[14], regulators have concluded that, in order for a return to be fair, it must also meet the tests of "capital attraction" and "financial integrity"[15]. In this connection, the Régie de l'Énergie du Québec (Régie) has in several decisions accepted the view that the cost of capital must be evaluated on the basis of the fundamental principle of the market opportunity cost of capital and that the rate of return must allow the regulated entity to assure and maintain its capacity to attract funds under reasonable conditions[16]. In other cases, intervenors have drawn regulators' attention to the Lamont text[17]. In still others, the regulator has referred obliquely to the objectives of fairness and capital attraction[18].

The traditional approach to ROE determinations Prior to the mid-1990's, the practice of Canadian gas utilities was to make rate applications, often every one or two years[19], generally requiring re-determination of their ROEs as one component of the total revenue requirement that could be recovered in rates. In these proceedings, as the Ontario Energy Board (OEB) has noted, four main approaches were traditionally used by experts to establish a fair ROE. The Comparable Earnings Test (CE), Discounted Cash Flow (DCF) test, Capital Asset Pricing Model (CAPM) and Equity Risk Premium (ERP) test [20], are all used in varying degrees to formulate an opinion regarding a fair return to investors for the test year. Parties, the OEB observed, have generally relied on a combination of these models to establish a utility's ROE. In a combined approach, the OEB and experts before it have assigned different weights to the results of the various tests in order to give more significance to those models which they consider to be the most relevant[21].

Within the compass of what must be a relatively short paper, it is impossible to trace the outworking of this approach by each of the Canadian gas utility regulators. However, successive NEB Reasons for Decision respecting TransCanada PipeLines' rates illustrate how this approach was followed by one regulator over the quarter century to 1994.

That Board, like others, was careful from the start to point out that "The final conclusion as to what is enough but not too much in the way of return is not precisely supportable on a mathematical basis."[22] "Many tests and techniques for assisting the process of reaching a just decision have been used" the Board said "but no single test is conclusive, nor is any group of them definitive: whatever tests may be used, in the last analysis the adjudicating body can not escape the responsibility of exercising judgment as to what, in a stated set of circumstances, is a just and reasonable return or rate of return, or what is a range of justness and reasonableness of return or rate of return."[23] Such reference to the necessity of the exercise of judgment in making return awards is a recurring theme in Canadian regulatory decisions over the years.[24]

Diversity of tests applied in the traditional approach Reverting to the NEB's practice, in the early years of the Board's "active" regulation of TransCanada's tolls, comparable earnings appear to have been at the centre of its attention. Thus: "The Board concludes, based primarily on the comparable earnings analysis of Canadian industrials which are reasonable alternative investment opportunities for the applicant's shareholders, that a return of…is appropriate for the test year…"[25] In an oil pipeline rate case about this time, there was applicant evidence "…that statistics relating to US utilities and industrials deserve perhaps a greater weight in the assessment of the current cost of equity capital than similar Canadian statistics." The Board however disagreed and expressed the belief that "…far greater weight should have been given to Canadian data…Accordingly the Board was particularly interested in the statistics presented relating to Canadian industrials…"[26] and concluded "…that the cost of equity should be equal to or slightly less than the opportunity cost of investment in such companies."[27]

By 1978, the evidence put before the Board included CE and DCF tests, the latter to measure "capital attraction", but additionally the beginnings of the ERP approach appeared. The applicant, TransCanada, was cited to the effect that "…a reasonable ROE could also be inferred from an examination of the yield differentials maintained in the past between long term bonds and those of an equity nature in the regulated industry".[28]

However, in that particular case, the Board again stated that it paid particular consideration to "…the CE of Canadian industrials which it believes to be representative of reasonable alternative investment opportunities for the applicant's shareholders."[29]

Over time, the ERP becomes the focus By 1981, intervenor evidence was being filed before the NEB and it related to the DCF method while the applicant relied primarily on the CE test[30]. However, within a couple of years something of a pattern had been established that was to last until the mid-1990s with the applicant and one intervenor filing CE, DCF and ERP evidence while gas-producer intervenors were focussing their efforts on the DCF approach.[31] In assessing this spectrum of evidence, the NEB tended over time to place at first "slightly more" reliance on ERP, to find inherent distortions in the CE data that it received and to be concerned about the results of the DCF test. By the time of the last rate hearing prior to the generic cost of capital proceeding, the Board found that "…in the light of recent and prevailing financial market conditions, neither the DCF test nor the CE test currently yield reliable results…" Accordingly these tests were given little or no weight in the Board's decision" and instead the Board was of the view that "…the ERP was the primary measure of investors' required returns in the circumstances of this case." However, the Board was careful to state its view that these tests (CE, DCF) may prove useful under different economic conditions.[32]

This era during which Canadian regulators determined ROE awards by reviewing evidence from multiple tests and applying their own judgment was summarized for the British Columbia Utilities Commission (BCUC, the BC Commission) in evidence and referred to by the Commission in a 2006 decision[33] as follows:

> "The evidence is that up to the 1960s the principal methodology to determine fair rates of return was CE, as, according to Dr. Booth, the DCF method and the ERP method which was derived from the CAPM, were developed in the 1960s. By the 1980s all three methodologies were in use in Canada. In the early 1990s capital markets in Canada fell into considerable turmoil, causing DCF and CE to give unreliable results, which resulted
> in the ERP becoming the main, if not the sole, methodology used by regulatory bodies in Canada to establish fair rates of return…The DCF and CE methods have never managed to restore themselves to favour in regulatory bodies' eyes...In the United States the DCF and CAPM methods got their start in the 1970s and have survived nearly unchanged as the primary rate of return methods, with the DCF the virtual default method in practically all U.S. regulatory jurisdictions."[34]

Search for a generic approach to ROE The context for the search by Canadian regulators for a generic approach to ROE was characterized by: frequent rate applications; repetitive evidence, often provided by the same expert witnesses, on the three principal tests; growing disenchantment with the CE and DCF tests; and increasing reliance on the ERP approach. That search was led by the BC Commission which "…was the first regulatory agency in Canada to examine the applicability of a generic, formula-based approach to setting a natural gas or electric utility ROE as a means of improving the efficiency and effectiveness of the regulatory process."[35]

British Columbia In its June 1994 decision resulting from that search,[36] the BC Commission expressed the view that the DCF test was of little use in the present economic climate, that CE raised a circularity problem when it was based on utilities data and that primary reliance should be placed on risk premium tests, with CE and DCF as checks. The Commission's view was that generic hearings produce cost savings and better quality of evidence because a variety of experts are gathered at a single point in time. This view has been borne out by the subsequent experiences of, for example, the Alberta Board and the NEB.

National Energy Board When the NEB reported its generic return decision nine months later in March 1995, it found that CE was only useful as a check, that there were practical limitations on the DCF method and that most experts gave primary weight to the ERP, which the Board also did. Annual adjustments in the resulting ROE were to be in a ratio of 0.75 of the forecasted change in the yields of Government of Canada long-term bonds (long Canadas).[37] The NEB later referred to this as "the RH-2-94 formula".

Manitoba Two months after that, the Manitoba Board Public Utilities Board (Manitoba Board, MPUB) decided a gas distributor rate case, prior to which the applicant had proposed a mechanical formula to adjust the Board's then-currently allowed ROE. The Board approved a spread, effectively an ERP, between long Canadas and the ROE for the distributor and an adjustment factor of 0.80 of the change in the underlying long Canada bond yields.[38]

Ontario The OEB has since 1997 followed its own guidelines on a formula-based return on common equity for utilities under its regulation.[39] The initial setup involved establishing a just and reasonable return applicable to each of the Ontario local distribution companies. This base comprised a forecasted yield on long Canadas for the test year to which was added an appropriate premium. The primary methodological approach to be used in evaluating the appropriate risk premium was the ERP. The annual adjustment factor proposed was 0.75 of the difference between the forecasted long Canadas yield and the corresponding forecasted yield for the immediately preceding year. The OEB gave three reasons for adopting the formula approach to ROE. The first was regulatory efficiency, already mentioned. The second was the weight of experience of other Canadian jurisdictions which had reviewed the issue and adopted a formula-based ERP. The third was that it may provide a first step towards formulaic rate making such as incentive rates.[40]

Alberta Alberta was the fifth jurisdiction to adopt a generic approach, which was done by a decision of July 2, 2004. The award for 2004 was based on the CAPM estimate, which the Alberta Energy and Utilities Board (Alberta Board, EUB) found was supported by no less than seven other methods examined in evidence while the Board did not put any weight on four other methods, including DCF and CE.[41] In this connection it is worth noting that the Board took the position that the CE test is not equivalent to the (Lamont) comparable investment test. The Board observed that the CE test measures actual earnings on actual book value of comparable companies, however it does not measure the return "…it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise."[42] This conceptual concern was one of the reasons the Board gave to place no weight on the CE test. Nevertheless, the Board did consider that there may be other measures of comparable investments that should be considered in establishing an appropriate ROE. It went on to examine eight possible ones.[43] [44] As to the adjustment mechanism, the Alberta Board concluded that an adjustment to the generic ROE based on 0.75 of the change in forecasted long-Canada bond yield would be appropriate, beginning in 2005.[45]

Québec The Régie has since its decision D-99-11 of 10 February 1999 respecting a rates application by Gas Métropolitain, applied a *de facto* generic ROE based on the CAPM model with an annual adjustment equal to 0.75 of the forecasted change in the risk-free return.[46] This approach was reconsidered in 2007: the ERP was adjusted marginally upwards on the assessment that Gaz Métropolitan's risk had increased compared to that of the benchmark distribution utility. The adjustment mechanism was to be left unchanged through 2009. In the 2007 proceeding, the applicant introduced as an alternative to CAPM, for the first time in Canada, the Fama-French model, which is used in the financial industry, but so far used only once in the United States in the regulatory context and never before in Canada.[47] Even though the two models differ, the objective of both is to estimate the return an investor expects to earn on an investment in securities having a certain risk. The main difference between the two approaches is in the method used to express that risk which, the applicant contended, Fama-French does better than CAPM for utility-type businesses. The Régie however did not retain the Fama-French model for establishing the rate of return in this decision: the Régie considered that the application of that model to regulated enterprises has not been sufficiently examined to date to be used as a basis for fixing the rate of return of a distributor.[48]

The generic approach reviewed and reconfirmed Two of the regulators who pioneered the generic ROE with automatic adjustment mechanism (AAM)—the BC Commission[49] and the NEB[50]—subsequently reviewed their decisions of the mid-1990s. After again receiving and reviewing much expert testimony, in the NEB case on two separate occasions (2002, 2005), the established methodology was reconfirmed by both. Indeed, one considered that "It is clear the ERP methodology is the "gold standard" for Canadian regulators..." and stated that "…the Commission Panel will give primary weight to its application and results…"[51]

A new test rejected TransCanada recommended in the RH-4-2001 NEB proceeding that the Board adopt an After Tax Weighted Average Cost of Capital (ATWACC) methodology to establish a fair return for its mainline. This was a new methodology as far as the NEB was concerned and it rejected it, just as the Régie was in 2007 to reject the Fama-French test, and it reaffirmed the ERP.[52] [53]

Legal obligation to apply the FRS? In its consideration of the application for review of its 2002 decision (RH-R-1-2002), the NEB refuted the assertion of TransCanada that the Board "is required by law to apply the comparable investment, financial integrity and capital attraction standards to determine a fair return for the Mainline" as an overstatement of the law on this issue. The Board went on to note that in its decision which was under review (RH-1-2002), it had agreed that the three components of the FRS, along with the balancing of customer and investor interests should be attributes of a fair return. The Board further noted the statement it had made in RH-1-2002 that these principles are reflected in the various accepted methodologies to establish cost of equity capital, such as the ERP approach, which is the basis of the RH-2-94 Formula and that no one took issue with this statement. In the Board's view, it was implicit that the application of a test that reflects these standards would result in a return that meets these standards. Therefore, the Board did not have to state explicitly that the resulting return would meet the comparable investment, financial integrity and capital attraction standards. The Board stated that an express finding, such as was sought by TransCanada, which discharges the fundamental legal obligation of the regulator is not necessary when the standards that must be met are imbedded in the methodology used to determine the return. The Board also considered that there is no legal obligation to use an FRS, comprised of the comparable investment, financial integrity and capital attraction standards to determine tolls. Rather, in normal circumstances, a fair return established by the Board should meet those three elements. This, the Board stated, was accomplished through the methodology that was used to determine the return.[54] This issue was revisited in depth by the NEB in RH-2-2004, Phase II, which followed the decision of the FCA in TCPL v. NEB. The Board stated that it "…also agrees with TransCanada that the case law establishes that it is the overall return on capital to the company which ought to meet the comparable investment, financial integrity and capital attraction requirements of the fair return standard."[55] The Board went on to say that it is not required to meet the FRS by subscribing to any particular methodology or solely by examining evidence on overall return (TCPL had suggested neither). It concluded that it would ensure that each element going into the traditional methodology is "reasonable", then "…uses its judgment to ensure that the resulting return is a fair return in accordance with the legal requirements."[56] In summary, the NEB in RH-2-2004 Phase II accepted that the law requires application of the FRS, including the comparable investment, capital attraction and financial integrity standards, in determining the overall return, but does not stipulate any particular methodology for doing so.

Risk-free rate critiqued The applicant before the BC Commission in 2006 stated, in the words of the Decision, that "the theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. However, the application of the model typically assumes that the return on the market is highly correlated with the risk free rate, that is, that the equity market return and the risk-free rate move in tandem. Similarly, an ROE formula that is predicated on a close tracking between the allowed return and the risk-free rate assumes the risk-free rate and the return on the market are highly correlated. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long term government bond yield as a proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the "true" risk-free rate, including:

> • the yield on long-term government bonds reflects the impact of monetary and fiscal policy;
> • yields on long-term government bonds may reflect shifting degrees of investors' risk aversion; and
> • long-term government bond yields are not risk-free; they are subject to interest rate risk."[57]

This critique of the risk-free rate and the relationship of market returns to that rate, although recorded by the Commission, was not responded to in the Commission's decision.

Convergence among Canadian gas utility regulators Recent years have seen a rapid and complete convergence among the five Canadian utility regulators who have major gas distribution and transmission entities under their jurisdictions. All now base their ROE awards essentially on judgments as to an appropriate base year ROE for a benchmark utility. In every case, this base year award uses a risk free rate plus an ERP with, in some cases, an allowance for flotation costs. Subsequent annual adjustments are made mechanically on the basis of 0.75 of the changes in the forecasted long Canadas yields.[58]

Insofar as incumbent utilities are affected, the generic ROE plus AAM is entrenched in Canadian regulatory practice—Canadian regulators have in the last dozen years affirmed and reaffirmed the generic ROE based essentially on the ERP methodology as the sole method of awarding and, through the associated AAM, varying the returns on equity for gas utility investors. This position has withstood several review applications and one appeal to the courts. In one important case, as a result of a negotiated settlement, it cannot be reopened before 2012.[59]

Contrast with American practice This Canadian situation stands in sharp contrast with that in the USA with which Canada shares the tradition of cost of service utility regulation where the fairness of return on investment is evaluated against the opportunity cost of capital.[60] There, only two commissions undertook what turned out to be lengthy, expensive and ultimately unsuccessful searches for a generic solution. There is a longstanding seeming disinterest on the part of the American regulatory community in pursuing this search. Instead, where rate cases are not settled, U.S. regulators continue to rely on the application of judgment to multiple test results[61] with DCF as the default mechanism[62].

3. Results from the mid-1990s

The number and duration of rate proceedings involving ROE evidence significantly reduced In the period 1971-1994 inclusive, the NEB in respect of only one company, TransCanada, averaged one rate proceeding every 18 months. It is likely that, with TransCanada having now settled its tolls for the period 1 January 2007 through 31 December 2011, the similar hearings in the period 1995-2011 will turn out to have averaged one per eight years. Similar regulatory efficiencies affecting a large number of utilities, electric as well as gas, are being found by the principal provincial jurisdictions.

In some jurisdictions, the way paved for long-term settlements of rate matters The NEB's experience again furnishes an example. The Board's decision on a generic rate of return may have been a factor enabling TransCanada[63] and Westcoast Energy[64] to achieve their first multi-year negotiated settlements of remaining toll and tariff matters. Note that one of the objectives of both settlements was "to maintain ("or improve", in the case of TransCanada) the financial integrity…" of the pipeline company.[65] [66]

Regarding the Alberta Board, on the one hand a month after bringing down its Generic Cost of Capital decision in July 2004 approved NOVA Gas Transmission Ltd's (NGTL) application to commence negotiated settlement discussions. These eventuated in a settlement of all revenue requirement issues, return on equity being treated as a flow-through item, for the three-year maximum period allowed by the Board, commencing 1 January 2005.[67] On the other hand, prior to the implementation of the ROE formula, Northwestern Utilities and ATCO Electric both negotiated settlements. Since the introduction of the formula there have been no long term settlements other than NGTL.

The BC Commission has approved a Settlement Agreement for Terasen Gas for 2004-2007, incorporating a Performance-Based Rate Plan,[68] and subsequently approved its extension for 2008-2009.[69]

As to pipelines under the NEB's jurisdiction, two points are notable. First, settlements of toll issues have been the norm for oil pipelines since the mid-1990's. Second, all new oil and gas pipelines have applied for tolls, based on settlements, where the ROE exceeds that generated by the Board's generic formula, often by a generous amount.

Transmission utilities' incentive agreements have provided for efficiency gains and sharing of those gains between customers and utility owners Annual or biennial adversarial proceedings relating to ROE are for transmission businesses now a thing of the past. This may have encouraged and enabled parties to settlement negotiations to build-in to the resulting agreements features that encourage these pipelines to search for efficiencies with the prospect of retaining for the investor a share of those efficiencies. All of the negotiated settlements mentioned in the previous paragraph incorporate such features in one form or another. In a degree, these shared savings mechanisms have cushioned the impact of declining ROEs resulting from the application of the generic ROE decisions in an environment of declining bond yields. For example, in the letter to shareholders accompanying TransCanada's 1996 Annual Report, the management commented that there had been a one per cent decline in the rate of return on common equity allowed by the NEB in 1996. The letter went on to say "That one per cent represented a reduction in 1995 earnings of about $21 million that had to be made up. A substantial part of it came from discretionary revenue earned under an incentive agreement reached late in 1995 between TransCanada and its customers. Incentive regulation allows TransCanada to share in discretionary revenues and cost savings."[70] This cushioning effect may be available to some pipelines on a continuing basis, but in a regulatory context its results must not be seen as an element of a fair return. Fair return relates to the opportunity cost of capital. Earnings from incentive agreements are rewards for extraordinary cost-savings and for entrepreneurship in devising service offerings that create value for which shippers are willing to pay. As the Federal Court of Appeal reminded in the 2004 TransCanada decision,[71] the fair return must be determined independently of its impact upon resulting customer rates.

But Canadian and U.S. regulators' ROE practices are now widely divergent after decades of essentially parallel approaches Canadians have converged on the generic approach using essentially anticipated risk-free rates plus ERP and adjusting by a ratio to anticipated changes in risk-free rates. In the U.S., the federal and one state commission attempted to regularize the ROE component of rate cases, but failed to do so. One commentator has stated that "Efforts to make the process objective and mechanical are futile as an administrative and practical matter."[72] Instead, where cases are litigated, commissions continue to refer to the legal standards set by the landmark U.S. Supreme Court decisions in Bluefield and Hope. The regulators receive and access data from quantitative financial models and apply informed judgment in order, as the California Pubic Utilities Commission (CPUC, California Commission) has put it, to arrive at "An ROE set at a level commensurate with market returns on investments having comparable risks, and adequate to enable a utility to attract investors to finance the replacement and expansion of a utility's facilities to fulfill its public utility obligations."[73] Moreover, U.S. regulators: have continued to accept evidence that depends in large part on data about other U.S. gas and electric companies' returns; have had at least some regard to short term bond rates; and in some cases have stated a consistent practice to moderate changes in the ROE relative to changes in interest rates in order to increase the stability of ROE over time.[74]

And Canadian gas utility ROEs have fallen significantly below those of American ones and below those of low risk North American industrials Historically, the ROEs of Canadian gas local distribution companies (LDCs) have approximately matched those in the U.S. industry. Since the inception of the generic ROE approach by Canadian regulators, the returns enjoyed by Canadians have fallen increasingly and significantly (up to 150 bp) below those of these comparables. This result arises despite the fact that independent analysis shows that business risks faced by LDCs in Canada do not significantly differ from those in the U.S.; that the greatest risk-determinant for utilities, regulatory risk, is comparable in Canada and the U.S.; and that tax differences do not matter to the comparison of Canadian and U.S.[75] [76]

ROEs for greenfield interprovincial and international pipelines In the "generic ROE era" it has become the practice for new pipelines subject to NEB jurisdiction to apply for tolls that have been the subject of prior negotiation with shippers. Typically, these tolls reflect ROEs about 300 or more basis points higher than incumbent pipelines, such as Foothills, TCPL, TQM and Westcoast, receive under the generic ROE.[77] Two points arise. First, this practice suggests that the NEB's generic ROE is insufficient to attract capital needed for greenfield projects. Second, one wonders whether this *de facto* vintaging of ROEs in the Canadian interprovincial and international pipeline sector breaches a fundamental principle of fairness.

4. Implications

On the one hand, the generic ROE has created regulatory economies and encouraged the search for other efficiencies in the sector The frequency of adversarial proceedings leading to ROE awards has been greatly reduced with consequent public and private savings. The generic ROE may have encouraged negotiated settlements of remaining rate issues, which typically incorporate elements of incentive rate-making encouraging efficiencies in investment and operations. Some utilities may have been able in this way to partially compensate for the low ROEs resulting from the application of the generic formula. However where that may have happened, it has been at the expense of greater risks by the utilities. Even with the presence of incentive features, there is no assurance that settlements will result in a "fair return" being earned each year of the settlement and over its lifetime, which could be as much as five years. The scope to achieve efficiencies while ensuring high quality of service may be exhausted and the overall return may fail to meet the fairness standard.

On the other hand, the generic ROE approach is mechanistic and necessarily suspends the further application of regulatory judgment for extended periods, marking a sharp break with past practice

- It was not uncommon in the past for regulators to expressly reject mechanistic approaches to ROE awards and stress the importance of judgment.[78] The initial generic decisions and any subsequent reviews, like the annual or biennial rate cases that preceded them, were based on careful assessment of much evidence and the application of informed regulatory judgments.

- However, once decisions are taken on a generic process, including the now universal AAM, the further application of judgment as to whether the FRS is being attained is suspended.[79] In principle, as the Alberta Board has observed, parties are free at any time to petition the regulator to consider a review of the adjustment formula in which, in Alberta, the petitioning party would bear the onus of demonstrating a material change in facts or circumstances from the evidence filed in its generic proceeding to merit a review of the formula.[80] In practice, the party's freedom to petition can be circumscribed for periods as long as five years as a result, for example, of a settlement agreement, a term which can therefore cover one or more economic cycles.

It would appear from work done prior to [81] and parallel with [82] this review that the FRS may not have been achieved on an ex-post basis This important conclusion is suggested by the comparison of Canadian gas LDCs' ROEs and the ROEs of U.S. gas utilities and North American low risk industrials, already referred to. It seems reasonable as an aspect of the industry oversight expected of regulators that, especially after a change as fundamental as the generic ROE, they would assess that change in terms of whether the results required *ex ante* by the FRS have in fact been achieved *ex post*, with particular regard to the opportunity cost of capital. Such an examination by regulators is particularly warranted because the generic ROE plus AAM effectively prevents regulated entities from routinely presenting evidence and argument as to whether *ex post* the resulting ROEs have indeed reflected opportunity pricing of the cost of capital and achieved other objectives of the FRS which the generic regime is intended prospectively to do.[83]

Two fundamental features driving ROE changes and arguably driving the "wedge" between Canadian LDC returns and others, namely the risk free rate and the AAM ratio appear to deserve critical examination

- On the first point, as noted in Section 2 above, while one applicant has critiqued the risk-free rate, the regulator involved (the BC Commission), although summarizing the applicant's concerns, did not respond to them. It is not difficult, for instance by reading the Bank of Canada's periodic comments on factors influencing rates to find reasons to question why LDC ROE's should be directly linked to bond rates.[84]

- On the second point, the AAM ratio of 0.75 (and the 0.80 chosen initially by one regulator) had some empirical support in the proceedings leading to the respective initial generic decisions. Also it received principled support by the applicants in a number of proceedings. However it appears not subsequently to have been critically evaluated in terms of the behaviours of equity returns of comparable unregulated sectors in relation to changing bond yields in the dozen years since the earliest Canadian generic ROE decisions.

- Regarding U.S. LDC returns, the work of Concentric Energy Advisers for the OEB has shown a much lower coefficient of regression (0.46) between U.S. ROEs and long bonds compared to Ontario ROEs (0.86): in other words, that is for every one percentage point change in interest rates, the Ontario ROEs change by 86 basis points while U.S. ROEs change by 46 basis points.[85]

The generic, mechanistic ROE including the AAM may require some reconsideration, if the FRS is to be achieved on a going forward basis

The work carried out by Concentric for the OEB and by National Economic Research Associates (NERA) for the CGA identifies concerns that sow a doubt as to the ability of the present design of the generic ROE to continuously meet the fair return standard. It is indisputable that this bold and widely-welcomed initiative of Canadian regulators has entrained and encouraged valuable public and private efficiencies. However, in exchange, the generic ROE has reduced the opportunities, present in previous practice, to periodically exercise oversight of this critical element in the revenue requirement, review the results of a variety of tests, apply informed judgments to them, and recalibrate their ROE awards in conformity with their understanding of the FRS. Even though regulators are willing to entertain applications for review of the generic approach, it remains that there are necessarily fewer examinations of the relevant data to ensure the generic formula plus the AAM continues to produce end results which meet the FRS.

Examination of the results of the generic approach, ex-post, suggests that, in an environment where interest rates have been, first, falling and then stabilizing at low levels, the generic ROE plus an AAM that tracks changes in expected bond yields in a ratio of 0.75 may have pulled ROEs down excessively in relation to the FRS and that, in the judgement of Concentric, "This may require consideration of additional qualitative and financial metrics in making the ROE determination."[86] In other words, what was found to be "fair and reasonable" or "just and reasonable" by careful examination of multiple tests and the appropriate exercise of informed judgment, may no longer be so after successive adjustments by admittedly-simple AAMs taking place in continuously changing economic and business conditions.

The remarkable convergence among Canadian gas utility regulators may be an obstacle to reappraisal of the ERP plus AAM approach to the generic ROE

The NEB in dealing with TransCanada's Fair Return Application dated 6 June 2001, centred on a novel After Tax Weighted Average Cost of Capital (ATWACC) approach, stated: "In summary, in the Board's view, the lack of regulatory precedent is not a barrier to the adoption of a new approach to regulation. However, in the absence of such precedent and in the absence of any support from stakeholders for the proposed change (meaning to the ATWACC approach—authors), the Board's analysis of the proposal should show a clear benefit to be derived from the new approach when compared with previous acceptable approaches."[87] As already noted, the Régie in 2007 was similarly faced with a novel approach proposed by Gaz Métroplitan, the Fama-French model which, according to the evidence, had never before been used in Canada and only once in the USA. The Régie decided not to retain Fama-French as a method of fixing the ROE because it had not been sufficiently examined to date to be used as a basis for fixing the rate of return of a distributor.[88]

In view of the foregoing, it is reasonable to pose the questions "Is there likely to be regulatory precedent and stakeholder support for initiatives by the gas utility industry for review of and change in the generic ROE?"

As to "regulatory precedent", it may not be easy for any Canadian regulator to "break ranks" with the rest, particularly after several have relatively recently reviewed their generic ROE practices and decided against major changes to them. Having taken place, regulatory convergence may be a powerful disincentive even for needed changes.

As to "stakeholder support", it appears that Canadian gas utility stakeholders are continuing in their virtually unanimous support of the respective regulators' established approaches. In the environment of generally-declining bond yields, the present design of the generic ROE has worked to the short-term economic advantage of industrial users, residential consumers, producers and shippers. This has generated an attitude, common in the regulatory world, of "what we have we hold". As long as the provision of safe and adequate service does not seem to be immediately at risk, this attitude is likely to continue. Broad stakeholder support for major revisions favourable to the utilities seems unlikely to materialize so long as utilities seem able to attract capital and avoid impairing their financial integrity. It appears doubtful, however, that the FRS is satisfied by these considerations alone if the end result is unfair relative to returns available from investments in companies of similar risk.

Desirable next steps It would be helpful if, at the same time as specific cases occasionally come before individual regulators,[89] some further studies of general application were to be carried out. It is not the purpose of this paper to propose an alternative framework for ROE determination. However, any reconsideration should clearly take place against the background of an *ex post* examination of the results of the generic approach in terms of the comparability of the resulting returns with non-utility and utility comparators. It must include the fundamentals of the present design, namely the choice of the risk-free rate, the appropriate measurement of the risk premium and the adjustment mechanism. And it cannot exclude consideration of the place of the DCF model, given its acceptability to a majority of North American regulators. Finally, in an era of North American economic and business integration, the question must be asked "Can Canadian gas utilities successfully compete for capital if their regulators continue to award lower returns on generally thinner equity shares than those enjoyed by the American industry?"

Absent such a reconsideration and consequent adjustment, in an environment of continuing very low interest rates and bond yields, the present generic ROE formula alone may not be protecting the public interest in the provision by incumbent utilities of a robust, flexible natural gas delivery structure financially strong to support future sustainability of our energy economy.

ENDNOTES

[1] The jurisdiction is Alberta. The test is the traditional comparable earnings one. See under heading 2 "Application", subheading "Alberta" on page 16.
[2] The word "stakeholder" has become an undefined term of art, particularly in NEB decisions on applications reflecting negotiated settlements, where it may be used as a synonym for parties to those settlements. In this paper, by "stakeholders" are meant parties, other than utility managements and shareholders, who have an economic interest in gas utility rates or tolls and who routinely take part in related regulatory proceedings and in settlement discussions. In this definition, depending on the nature of the utility, "stakeholder" can mean gas producer; shipper; exporter; industrial, commercial or residential consumer; or provincial government.
[3] An example may be the application to the NEB by Gazoduc TransQuébec & Maritimes (TQM) for Cost of Capital for 2007 and 2008, revised filing December 18, 2007, the first such application by that company since 1994. However, because of the complexity of the issues involved in this application and because of language considerations, a longer than normal hearing process is required. The hearing is presently scheduled to commence 23 September 2008, which means that a decision on this hearing would not be released until early 2009. See National Energy Board letter to TQM of 22 January 2008, file OF-Tolls-Group1-T201-2007-03 01.
[4] *Return on Equity: Allowed Returns for Canadian Gas Utilities*. A Discussion Paper Developed by the Canadian Gas Association. Summer 2007. 20 pages in bilingual format.
[5] The Lamont decision relates to "…a fair return…on the capital invested in its enterprise…" (S.C.R., 1929, page 193). However, the costs of debt and any preferred shares, assuming they are prudently incurred, are usually taken as a cost to be flowed directly through to rates via the cost of service. The ROE is therefore the salient variable in the fair return on the (total) capital invested in the enterprise. The discussion in this paper relates entirely to regulators' awards for the return on the owners' equity investment. It does not extend to consideration of what those awards mean in terms of return on the total capital invested by the utility in question even though, and the authors acknowledge this, the entire focus of the Lamont decision is on return on the total capital.
[6] By "Canadian gas utility regulators" is meant the relevant regulatory boards and commissions of Alberta, British Columbia, Canada, Manitoba, Ontario and Quebec.
[7] National Energy Board (NEB). Reasons for Decision (RfD). In the Matter of the Application under Part IV of the National Energy Board Act of Trans-Canada Pipelines Limited, RH-1-70, December 1971, pages 6 – 6 to 6 – 9.
[8] NEB, RfD, TransCanada et al. Cost of Capital. RH-2-94, March 1995.
[9] NEB, RfD, TransCanada PipeLines Limited. Cost of Capital (Fair Return Application of 6 June 2001). RH-4-2001, June 2002, pages 8-12.
[10] NEB, RfD, TransCanada PipeLines Limited. Review of RH-4-2001 Cost of Capital Decision. RH-R-1-2002, February 2003, Chapter 3: Fair Return Standard, pages 6-12.
[11] NEB, RfD, TransCanada PipeLines Limited. Cost of Capital. RH-2-2004 Phase II, April 2005, Chapter 2 Legal Framework for Determining a Fair Return, pages 8-20. In this context, the NEB noted the finding of the Federal Court of Appeal in TransCanada's unsuccessful appeal of the Board's 2002 decision. The Court, the Board stated, found that the impact of any resulting toll increases on customers is not a relevant consideration in the determination of the required rate of return on equity.
[12] Since January 1, 2008 the economic regulatory functions of the former EUB in respect of investor-owned and certain municipally-owned utilities are being exercised by the Alberta Utilities Commission (AUC).
[13] Energy and Utilities Board (EUB), Decision 2004-052, Generic Cost of Capital, July 2, 2004, Section 3.2 Relevant Judicial Decisions, pages 12-13.
[14] The principal American Supreme Court decisions are *Bluefield Water Works & Improvement Company vs. Public Service Commission of The State of West Virginia et al 262 U.S. 679 [1923]* (Bluefield) and *Federal Power Commission et al vs. Hope Natural Gas Co., 320 U.S.591* [1944] (Hope). They are cited by the NEB in RH-1-70 (op.cit.) at 6 – 8 and 6 – 9, RH-4-2001 (op.cit.) at page 8 and RH-2-2004 (op.cit.) at pages 14-16.

[15] This is borne out by the Alberta Board in EUB Decision 2004-052 (op.cit.) where after quoting from Northwestern, Hope and Bluefield, it stated at page 13 that "The Board notes that no party took issue with the general consensus that in order for a return to be fair, it must meet the tests of "comparable investment", "capital attraction" and "financial integrity" described in the above decisions.
[16] « La Régie accepte…que l'évaluation du coût des capitaux propres sur base présumée doit reposer sur le principe fondamental du coût d'opportunité de marché des capitaux propres…La Régie est d'avis que le taux de rendement accordé au Distributeur doit lui permettre d'assurer et de maintenir sa capacité d'attirer les fonds à des conditions raisonnables » Source : Régie de l'Énergie du Québec. Hydro-Québec. D-2003-93. 2 mars 2003, à la page 70. The same principles had earlier been expressed in Régie de l'Énergie du Québec. Hydro-Québec. D-2002-95. 30 avril 2002, à la page 163. These were admittedly electric utility cases, however since the Régie uses essentially the same methodology to determine its ROE awards for Québec gas utilities, it is reasonable to suppose that it does so in pursuit of the same principles of opportunity cost of capital and capital attraction as it applies to the electrical sector.
[17] Manitoba Public Utilities Board Act. Centra Gas Manitoba Inc. General Rate Application. Order No. 99/07, July 27, 2007, page 65.
[18] Ontario Energy Board (OEB) Compendium to Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities (OEB Compendium). Chapter 2: Current OEB Approach, page 2, which reads in part "The Board's objective in setting the rate of return on rate base is to ensure that the utility is provided with a fair return which enables it to meet its obligations and maintain its capability of attracting capital".
[19] By way of example, TransCanada PipeLines averaged one such application to the NEB per 18 months in the period 1971-1994 inclusive.
[20] The NEB in RH-4-2001 (op.cit.) at page ix (Glossary of Terms) characterizes the ERP method as a family of models that includes CAPM and ECAPM (Empirical Capital Assets Pricing Model). See also RH-4-2001 page 48, second paragraph.
[21] OEB, op.cit.
[22] NEB, RH-1-70 op cit, page 6 – 6.
[23] NEB, op cit, pages 6 – 2 and 6 – 3.
[24] The application of informed judgement is similarly a constant in American regulators' decisions in utility rate cases. Consider the following from the California Commission's December 15, 2005 Decision 05-12-043 on the Test Year 2006 Return on Equity for the Major Utilities (Pacific Gas and Electric [PG&E], Southern California Edison [SCE] and San Diego Gas and Electric [SDG&E]). At page 23, the Commission stated "In the final analysis, it is the application of informed judgment, not the precision of financial models, which is the key to selecting a specific ROE estimate. We affirmed this view in D.89-10-031, which established ROEs for GTE California, Inc. and Pacific Bell, noting that we continue to view the financial models with considerable skepticism." The Commission then uses the term "informed judgment" eight times in respect of its own decision-taking. As a matter of interest the resulting ROE awards for 2006 were, for PG&E 11.35%; for SCE 11.60%; and for SDG&E 10.70%.
[25] NEB, RfD, TransCanada PipeLines Limited, RH-3-76, December 1976 page 4 – 13.
[26] NEB, RfD, Interprovincial Pipeline Limited, RH-2-76, December 1977, page 6 – 23.
[27] NEB, RH-2-76, op cit, page 6 – 26.
[28] NEB, RfD, TransCanada PipeLines Limited, RH-1-78, July 1978, page 5 – 9.
[29] Ibid.
[30] NEB, RfD, TransCanada PipeLines Limited, RH-4-81, Phase I, August 1981, pages 4 – 5 and 4 – 6.
[31] NEB, RfD, TransCanada PipeLines Limited, RH-3-1982, July 1982, pages 3 – 10 to 3 – 12.
[32] NEB, RfD, TransCanada PipeLines Limited RH-4-93, June 1994, page 27.
[33] BC Utilities Commission, Decision in the matter of Terasen et al, March 2, 2006, page 45.
[34] This statement is from an article by Dr. Jeff D. Makholm in Public Utilities Fortnightly, May 15, 2003, pages 12-18, "In Defense of the 'Gold Standard'". The fuller context is as follows: "The fair rate of return became a hotly contested issue in the early 1970s…The DCF and CAPM methods got their start at this time and have survived nearly unchanged as the primary rate of return methods, with the DCF the virtual default method in practically all U.S. regulatory jurisdictions." (Makholm, page 14, column 1).
[35] OEB, op cit, page 8.
[36] BC Utilities Commission, Decision in the matter of Return on Common Equity, BC Gas Utility et al, June 10, 1994, see especially pages 17-18.

[37] NEB, RfD, RH-2-94, TransCanada et al, Cost of Capital, March 1995.
[38] Manitoba Public Utilities Board Act, Order No.49/95, May 5, 1995 in an application by Centra Gas Manitoba Inc. The Manitoba Board in that decision reserved the right to require a full ROE hearing prior to the 1997 test year as a result of unusual or significant changes in the economy. However such a hearing did not take place. Centra Gas Manitoba was acquired by Manitoba Hydro, a provincial crown corporation, in 1999 and the ROE was subsequently replaced by a provision for a net income as part of Centra's costs, the allowed net income would not exceed the allowed return on equity under the Rate Base/Rate of Return methodology—see Manitoba Public Utilities Board Act, Order No. 103/05, July 12, 2005 in an Application by Centra Gas Manitoba Inc, page 40.
[39] OEB, Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities, March 1997 (not page numbered).
[40] OEB, Compendium, op cit, page 24, Section 5.1 Rationale for Draft Guidelines, Rationale for Adopting Formula ROE.
[41] EUB, Decision 2004-052, op cit, pages 15-31, Section 4.2 ROE Methodology and 2004 ROE.
[42] EUB, op cit, page 23.
[43] EUB, op.cit, Section 4.2.7 Other Measures of Comparable Investment, pages 24-30.
[44] The CE test was not the only one with which the EUB had difficulties. Thus, it is noted that the Alberta Board in Decision 2004-052, concluded "…that the results of the ERP tests other than CAPM would generally support a 2004 ROE above the Board's CAPM estimate, but that for the reasons set out above only limited weight should be placed on the results of the ERP tests other than CAPM." EUB op.cit. page 23.
[45] EUB, op cit, pages 31-32, Section 4.3 Annual Adjustment Mechanism.
[46] The Régie had previously applied the ERP approach but without an automatic adjustment feature, see for example Régie du Gaz Naturel, Décision D-96-31, 9 octobre 1996, Gaz Métropolitain, pages 69-70, La prime de risque du marché.
[47] Régie de l'énergie, Décision D-2007-116, Gaz Métropolitan, page 23.
[48] Ibid, pages 23-24.
[49] BC Utilities Commission, Decision in the matter of Terasen et al, March 2, 2006, op cit.
[50] NEB RfDs in TransCanada PipeLines Limited: Cost of Capital. RH-4-2001, June 2002; RH-R-1-2002, Review of RH-4-2001 February 2003; Cost of Capital. RH-2-2004 Phase II, April 2005. The RH-R-1-2002 decision was unsuccessfully appealed to the Federal Court of Appeal by TransCanada PipeLines (2004 FCA 149).
[51] BC Utilities Commission, op cit, page 52. Note that, while intending to give primary weight to the application and results of the ERP method, the Commission stated that it would need to apply judgment to the evidence before it.
[52] NEB RfD, TransCanada PipeLines Limited, RH-4-2001, pages 45-56.
[53] It may be noted that the EUB in Decision E99099, 1999/2000 Electric Tariff Applications, 25 November 1999 decided to "use both the traditional method and a modified ATWACC as tools to arrive at the fair return for (a number of electric utilities) with primary weight placed on the traditional method." (see page 328). The ATWACC evidence, which was accepted by the EUB with some modifications to its results, was submitted by the same witness (Dr.Vilbert) whose methodology and results were rejected by the NEB in RH-4-2001.
[54] NEB RfD, RH-R-1-2002, op cit, pages 11-12 Legal Obligation to use the FRS.
[55] NEB RfD, RH-2-2004, op.cit., page 19.
[56] Ibid.
[57] BCUC, Decision in Terasen et al, March 2, 2006, page 46.
[58] The degree of convergence as reflected in the annual ROE awards is remarkable. Thus, for year 2008 the range of ROEs is only about 50 basis points (bp) with La Régie at 8.91% (Gaz Métro) and the OEB at 8.39% and the EUB, NEB and the BCUC in the middle of the range with 8.75%, 8.71% and 8.62% respectively. Contrast this with the spread of 65 bp in the awards by one American regulator to three utilities for one year (footnote 25).
[59] The case is TransCanada's Canadian mainline. The negotiated settlement of March 2007 relates to the period 2007-2011 inclusive and provides that, during the Term, TransCanada will not pursue litigation of the NEB RH-2-94 ROE formula on behalf of… its Mainline System—see TransCanada PipeLines,

Application to the NEB, March 14, 2007: Application for Approval of a Negotiated Mainline Tolls Settlement and 2007 Mainline Tolls. Page 5 of 13, item 19. This Negotiated Settlement was approved by the NEB on 31 May 2007 by Order TG-06-2007.

[60] American regulators routinely cite their legal standard for fair return, essentially the Bluefield and Hope cases which are sometimes referred to also by Canadian regulators (examples: Alberta Board, NEB, see pages 11-12 above). The California Commission does so in the following terms in case D-05-12-043 (Test Year 2006 Return on Equity for the Major Energy Utilities) "The legal standard for setting the fair rate of return has been established by the United States Supreme Court in the Bluefield and Hope cases. The Bluefield decision states that a public utility is entitled to earn a return upon the value of its property employed for the convenience of the public and sets forth parameters to assess a reasonable return. Such return should be equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings attended by corresponding risks and uncertainties. That return should also be reasonably sufficient to assure confidence in the financial soundness of the utility, and adequate, under efficient management, to maintain and support its credit and to enable it to raise the money necessary for the proper discharge of its public duties. The Hope decision reinforces the Bluefield decision and emphasizes that such returns should be sufficient to cover operating expenses and capital costs of the business. The capital cost of business includes debt service and stock dividends. The return should also be commensurate with returns available on alternative investments of comparable risks.

[61] A sampling of relatively recent cases finds that the California Commission received and used DCF, CAPM and MRP evidence in case D-05-12-043 (see footnote 24), the Illinois Commerce Commission accepted DCF and CAPM evidence in a September 2005, once-in-a-decade decision on Northern Illinois Gas Company's rates; the New York Public Service Commission (NYPSC) received CAPM, CE, DCF and ERP evidence, found CE and ERP not to be particularly useful, and gave a 50/50 weighting to CAPM and DCF in a 2007 National Fuel Gas rate case (Case 07-G-0141).

[62] See above, text page 15 and footnote 34.

[63] NEB, Letter Decision, RH-2-95, December 1995. The TransCanada settlement covered the period 1 January 1996 through 31 December 1999.

[64] NEB, RfD, Westcoast Energy Inc., RH-2-97, Part II, August 1997. The Westcoast settlement covered the period 1 January 1997 through December 31, 2001.

[65] NEB, Compilation of Key Documents Related to the Board's RH-2-95 Decisions, TransCanada, June 1996, page 19, sub Article 1, item 1.2, v).

[66] NEB, RH-2-97, op cit, page 1, sub Article 1, item 1.2, (f).

[67] EUB, Decision 2005-057, NOVA Gas Transmission Ltd., 2005-2007 Revenue Requirement Settlement, July 7, 2005, see page 2 thereof.

[68] BCUC Order G-51-03 of 29 July 2003 for the initial term.

[69] BCUC Order G-33-07 of 23 March 2007 for the extension.

[70] "TransCanada PipeLines. Annual Report, 1996. Letter to Shareholders, page 4, final paragraph.

[71] Supra, page 9.

[72] Makholm, Jeff D., op cit, page 18, column 1.

[73] CPUC, D-05-12-043 on Test Year 2006 Return on Equity for the major energy utilities, Findings of Fact, paragraph 16.

[74] It is acknowledged that the Canadian "0.75 ratio" to forecasted changes in long Canadas has this effect.

[75] National Economic Research Associates (NERA). Allowed Return on (Gas Utility) Equity in Canada and the United States: An Economic, Financial and Institutional Analysis. Ken Gordon, Jeff Makholm, Wayne Olsen, November 2007. Tax differences are dealt with on page 13, business risk on pages 24-25 and regulatory risk on pages 25-32.

[76] Concentric Energy Advisors concluded for the OEB that "(6) On the whole, there are no evident fundamental differences in the business and operating risks facing Ontario utilities as compared to those facing U.S. companies or other provinces' utilities that would explain the difference in ROEs." See Concentric op. cit., Section VII Conclusions and Summary of Findings, paragraph (6) on page 57.

[77] *Alliance Pipeline Ltd* (Alliance) filed on 31 October 2007 its normal annual toll revisions to become effective 1 January 2008 The NEB filing ID is A16816. Alliance noted that the filed-for tolls reflect a base return on equity of 12%, subject to an incentive adjustment, on a deemed capital structure that provides for 30% equity. These are the same numbers as appeared in Alliance's original certificate application to the

NEB which was approved in November 1998 in GH-3-97. At the time of writing, Alliance's 2008 tolls are still interim.

Emera Brunswick Pipeline Company Ltd. reached a negotiated agreement for a monthly fixed toll that would cover all fixed charges including an equity return typically in the 11 to 14 percent range. NEB RfD Emera Brunswick Pipeline Company Ltd., GH-1-2006, May 2007, Section 7.1 Tolls and Tariffs, page 76

Mackenzie Valley Gas Pipeline, Section 3.1 of the August 2004 application in GH-1-2004 which is still under consideration presents toll principles that include a deemed capital structure based on 30% equity and an ROE equal to the NEB multi-pipeline ROE plus 2.21% for the initial 10 years, see page 3-4

Maritimes and Northeast Pipeline filed on 28 December 2007 a negotiated toll settlement for the calendar year 2008 which embodies an allowed ROE of 11.66 per cent on a deemed equity of 31.18%. NEB filing ID A17299.

[78] The seminal NEB decision in TransCanada's first rate application, RH-1-70 of December 1971 contains some important language relating to both points.

First, as to mechanistic approaches, the Board stated at page 6 – 6 "The final conclusion as to what is enough but not too much in the way of return, and rate of return, is not precisely supportable on a mathematical basis. If it were, one computer and a few programmers could replace all the regulatory boards in North America and dispense undeniable justice instantaneously."

Second, as to the exercise of judgment, the Board said at pages 6 – 2 and 6 – 3 that "Many tests and techniques for assisting the process of reaching a just decision have been used, but no single test is conclusive nor is any group of them definitive: whatever tests may be used, in the last analysis the adjudicating body can not escape the responsibility of exercising judgment as to what, in a stated set of circumstances, is a just and reasonable return or rate of return, or what is a range of justness and reasonableness of return or rate of return." These early comments by the NEB in a sense echo the view expressed by the SCC in Lamont where, in 1929 S.C.R., at page 199, the Court stated "The question of a fair rate of return on a risky investment is largely a matter of opinion, and is hardly capable of being reduced to certainty by evidence, and appears to be on one of the things entrusted by the statute to the judgment of the Board."

[79] Note that, in applying its automatic mechanism to adjust the rate of return on common equity, the BCUC initially advised the affected companies that it had "…reviewed the performance of the automatic mechanism to adjust the rate of return…and has determined that the mechanism has performed favourably." (Letters L-61-96, December 2, 1996; L-73-97 of December 2, 1997; L-89-98 of December 4, 1998). After 1998, however, the references to review and to favourable performance were dropped and the annual notification letters now simply state that "…the Commission has determined that the current ROE automatic adjustment mechanism results in an allowed return of…" (example: Letter L-93-07 of November 22, 2007). Essentially the same approach is followed by the EUB (Example: Order U2007-347 of 30 November 2007) and NEB (Example: Letter of 29 November 2007, File OF-TollsGen-RRCE 02).

[80] EUB Decision 2004-052, July 2, 2004, page 34.

[81] CGA op cit, Section 3: Maintaining a Fair Return, pages 14-17.

[82] NERA, op cit, particularly pages 7 – 11.

[83] Note that the EUB, in giving its reasons for establishing a standardized approach for setting an ROE, stated "An applicant is also free to apply to the Board to review the ROE formula in the manner provided for in this Decision. Even without an application by a particular party, the ROE formula will be subject to review in certain circumstances and in any event will be considered for review after five years." See EUB, Decision 2004-052, op.cit., page 8.

[84] A scan of Bank of Canada published comments for the past few years points to the following as rate-affecting monetary policy factors: economic growth; utilization of economic capacity; demand on the economy, domestic and export; inflation rates and inflation risks; U.S. economy and major sectors; global economy and major components EU, Japan, China; global markets, including commodity markets (e.g. energy), and their balances; Canada/USA exchange rates and the influence on the Canadian economy; cost of credit to firms and households; state of financial markets, Canada and abroad. These notes are based mainly on reading the Bank of Canada's semi-annual Monetary Report and Update available online at http://www.bank-banque-canada.ca/en/mpr/mpr_previous.html.

[85] Concentric Energy Advisors. A Comparative Analysis of Return on Equity of Natural Gas Utilities. Prepared for the OEB. June 14, 2007, pages 18-19. Concentric correctly point out that, "…as interest rates

have declined dramatically in Canada in the past ten years, one would expect the OEB formula to yield accordingly lower authorized ROEs. The formula, however, is symmetrical, and ROEs will most likely recover at a faster rate in Ontario than in the U.S., when interest rates begin to rise. In fact, if interest rates continue to steadily rise, the OEB adjustment formula could surpass and yield higher results than historical data suggest U.S. authorized returns would reach under the same circumstances."

[86] Ibid, page 57, last sentence in item 5.

[87] NEB, Rfd, RH-4-2001, heading Regulatory Precedent, at page 43.

[88] Régie de l'énergie. Décision D-2007-116., pages 23-24.

[89] The example has already been given of the 17 December 2007 application to the NEB by Gazoduc Trans-Québec et Maritimes for cost of capital determination for the years 2007 and 2008. See footnote 3, which also notes the lengthy hearing process which this application may involve, extending over about a 13-month period.

A Comparative Analysis of Return on Equity of Natural Gas Utilities

Prepared for:

The Ontario Energy Board

June 14, 2007

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Appendices

Disclaimer:

The views expressed in this report are those of Concentric Energy Advisors and do not necessarily represent the views of, and should not be attributed to, the Ontario Energy Board, any individual Board Member, or Board staff.

I. INTRODUCTION

The Ontario Energy Board (the "Board" or "OEB") retained Concentric Energy Advisors ("CEA") pursuant to Request for Proposal ("RFP") RFPOEBRPD2007-0227, "A Review of the Return on Equity of Gas Utilities in Ontario". The Board indicated in the RFP that it was interested in investigating statements from natural gas utilities that the Return on Equity ("ROE") awards in Ontario are lower than those of surrounding jurisdictions. To perform this investigation, the Board has requested a report that provides a comparison of awarded ROEs in other jurisdictions to those awarded in Ontario, including an analysis of the forces that contribute to those differences. Specifically, the OEB requested a written report that:

(1) Compares recent ROE awards in jurisdictions outside of Ontario to those awarded by the Board for natural gas utilities in the Province;

(2) Provides a review and analysis of whether Canadian utilities compete for capital on the same basis as utilities in the U.S.; and

(3) Addresses whether stand-alone companies compete for capital on the same basis as subsidiaries of larger holding companies.

This report provides CEA's analysis and findings related to these topics. Throughout the analysis, the focus is on similarities and differences between Canadian and U.S. companies, as Canada and the U.S. are generally considered to be highly comparable from a business standpoint and have fairly integrated economies. To provide additional perspective, CEA has also conducted a limited survey of ROE awards and methodologies for gas utilities in the U.K., Australia, and the Netherlands.

CEA's research for this report is based on publicly available data, supplemented by interviews with knowledgeable sources regarding specific features of Ontario's gas utility regulation. The report is not intended to be a comprehensive examination of the ROE for any specific company, but rather an overall examination of the major factors contributing to differences between ROE awards in Ontario and those in other jurisdictions.

II. EXECUTIVE SUMMARY

A gap between allowed ROEs for Ontario gas distribution companies and U.S. gas utilities has developed over the last ten years, coincident with the implementation of the Board's "Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities" in 1997. The current ROE differential between Canada and the U.S. is in the range of 1.50 percent to 2.00 percent (*i.e.*, 150 to 200 basis points). The purpose of this report is to examine the factors leading to this difference in allowed returns.

To begin, CEA examines the historical, pre-1997 relationship between allowed ROEs in Ontario and those found in the U.S. This comparison suggests that ROEs were in approximate parity in 1997. Thereafter, a widening gap has developed placing Ontario ROEs below those in the U.S. CEA's analysis points to interest rate trends combined with differing ROE methodologies as the principal factors underlying this development. The relative decrease in allowed returns in Canada is directly related to the past ten-year decline in interest rates, and all else remaining equal, can be expected to narrow or reverse itself in a period of rising interest rates.

Beyond the important interest rate determinant, this report looks to the companies themselves, as well as the jurisdictions and countries in which they operate, to determine whether there are any fundamental differences between Ontario gas utilities and those in the U.S. that would further explain ROE differences. While the specific characteristics of individual gas utilities and their respective regulatory environments can lead to differences in allowed returns, there are no apparent fundamental differences between gas utilities in Ontario and those of the U.S. that would cause the sizable gap in ROEs. In other words, taken as a whole, U.S. gas utilities are not demonstrably riskier than Canadian gas utilities.

CEA also extends the analysis beyond Canada and the U.S., to determine whether other countries, specifically the U.K., Australia, and the Netherlands, might form an adequate basis of comparison and thus allow for a larger population of comparable companies. While the gas markets in these countries bear certain resemblances to those of Canada and the U.S., there are a few substantial differences that weaken the comparison. Thus, allowed returns in these countries are not considered adequate benchmarks against which to examine ROEs in Ontario.

As a result of the interplay between the Canadian and U.S. markets, Canadian utilities compete for capital essentially on the same basis as utilities in the U.S. In the current market environment, no fundamental differences were identified that would indicate a significant difference in investor required returns between the two markets. Capital flows efficiently between these two markets, and over the long-term, equity investors earn nearly identical returns. On the issue of subsidiaries competing for capital we find that subsidiaries of larger holding companies ultimately compete for capital much like stand alone companies, as they must compete among their affiliates for parental investment. Nonetheless, the parental obligation to invest necessary capital to maintain system integrity will typically provide the wholly owned subsidiary sufficient capital to sustain operations, where no such provision exists for stand alone utilities. Over time, however, the equity returns must ultimately reward the parent or investor at the same rate as a similar investment of comparable risk. This "comparability standard" is a guiding principle in both Canadian and U.S. utility regulation.

It is important to note that this report does not attempt to estimate the "correct" ROE for the Ontario gas distributors, nor does it discuss which ROE calculation methodology or rate-setting approach is most appropriate for the Province. Lastly, no suggestions regarding future policy are proposed. Rather, this report quantifies the differences in existing allowed ROEs between jurisdictions and countries, and discusses the factors that most likely explain the disparity.

The information provided in this report is based on independent research and analysis of publicly available information, but is also guided by interviews with, and documentation provided by, key market participants and regulatory agencies, including the OEB, the National Energy Board ("NEB"), representatives from Union Gas ("Union"), Enbridge Gas Distribution ("Enbridge"), and other Canadian gas distributors, the Canadian Gas

Association ("CGA"), an industry analyst, and individuals who have represented customer groups and other interested parties in prior ROE proceedings.

Remainder of the Report

The remainder of this report is made up of five sections. Section III provides background on the theory and practice of ROE, including the applicable precedent and approaches used by various regulatory boards in Canada, the U.S., and the other countries studied. Section IV contains a discussion of ROE methodologies and a comparison of awards across different jurisdictions, as well as an assessment of risk factors for the companies in the sample population, and a discussion of what significant differences exist between gas distributors in Ontario and those in other jurisdictions. Section V presents a discussion of competition for capital in Canada versus the U.S., and in Section VI we provide a comparable assessment of stand-alone versus subsidiary companies. Section VII contains our overall conclusions.

III. ROE BACKGROUND

The setting of ROE, as a component of the rate of return on rate base for a regulated entity such as a natural gas distributor, meets three essential objectives: (1) to provide a return consistent with other businesses having similar or comparable risks; (2) to be adequate to support credit quality and access to capital; and (3) to balance investor and consumer interests. A return that is adequate to attract equity capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial integrity and providing just and reasonable rates. The ROE should be commensurate with the risks incurred by investors and comparable to the returns available elsewhere in the market for investments of equivalent risk. If a utility is allowed to earn its fair and reasonable ROE, both ratepayers and investors should benefit.

<u>ROE Precedent</u>:

The Supreme Court of Canada set out the fundamental requirements that a fair and reasonable return on capital should be met in its decision *re.: Northwestern Utilities vs. City of Edmonton,* 1929. As stated by Mr. Justice Lamont in that case:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise…. [1]

The NEB has further summarized its view that the fair return standard can be met by fulfilling three particular requirements. Specifically, a fair or reasonable return on capital should:

- Be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
- Enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and

[1] Northwestern Utilities v. City of Edmonton [1929] S.C.R. 186 (NUL 1929).

- Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).[2]

For a more detailed discussion of significant ROE-related decisions in Canada and the U.S., please see Appendix C to this report.

In Canada, the NEB regulates interprovincial and international pipelines, and thus determines the allowed ROEs for pipeline companies. Regulatory boards at the provincial level, such as the OEB, regulate Canadian local distribution companies ("LDCs"). Similarly, in the U.S., the Federal Energy Regulatory Commission ("FERC") regulates energy-related interstate commerce, while state boards are responsible, for the most part, for the regulation of U.S. LDCs.

Over the past decade, the formulas used to determine ROE awards by the NEB and the Canadian provinces (including Ontario) have largely utilized the "risk premium" method. The basic mechanism involves summing the forecasted yield for the long Government of Canada bond (30-year) for the test year with an equity risk premium. Subsequent adjustments to the ROE are based upon the application of an adjustment factor (*e.g.*, 75 percent) to the year-over-year change in the long-term forecasted bond yield. This adjustment is added to/subtracted from the previous year's rate of return, to obtain the current year's ROE. The long-term bond yield forecast is determined by taking the average of the three month and twelve month 10-year Canadian Bond forecasts plus a historical yield spread between the ten-year and thirty-year bonds.

By contrast, ROEs in the U.S. are more typically determined through rate proceedings in which a variety of analytical techniques, including the Discounted Cash Flow ("DCF") Model (single and multi-stage), the Capital Asset Pricing Model ("CAPM"), risk premium, and comparable earnings analyses, are presented. The state utility commission or FERC (for cases involving interstate commerce) ultimately decides the ROE of the subject utility based upon the evidence in the proceeding.

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2 Reasons for Decision, TransCanada PipeLines Limited, RH-2-2004, Phase II, April 2005, Cost of Capital.

While this report focuses on companies in Canada and the U.S., for further comparison it also provides a high level review of the methodologies for setting returns and the resulting ROEs in the U.K., Australia, and the Netherlands.

U.K.

In the U.K., the Office of Gas and Electricity Markets ("Ofgem") has adopted a price control, or "price cap", method for regulation of gas distributors. An alternative approach to rate-of-return regulation, the price-cap methodology allows for price increases owing to inflation, but also accounts for increases in productivity by the utilities, and shares those benefits with ratepayers. Under the price control, the Ofgem, the U.K.'s regulatory body, sets the initial base price of the utilities assets for a five year period. Price caps and related mechanisms are also utilized selectively in U.S. jurisdictions and in Canadian provinces.

One aspect of calculating the initial price level in the U.K. is to determine the cost of capital for the utilities. In 2000/2001, Ofgem set the cost of capital (utilizing the CAPM method to calculate the equity return component of the cost of capital) for the only gas distribution company existing as of that date (National Grid). National Grid has since divested four of its eight distribution networks, but the price controls have been maintained for the new owners. The 2000/2001 price control was to be in place from 2001 to 2006, but was recently extended through 2008. The ROEs for the U.K. gas distributors are provided in Table 4 of this report.

Australia

In Australia, the local gas distribution networks are regulated by each state's applicable regulatory commission. Most Australian states surveyed operate in a restructured gas market, in which the regulator has committed to retail competition and has unbundled (segregated) the utility's distribution function from the natural gas supply function. Similar to Ontario, utilities in these jurisdictions must compete with gas marketers for retail customers, and are often 'providers of last resort'. Gas distribution companies are subject to price caps, with an annual adjustment for changes in inflation and productivity. For most jurisdictions the prices are reviewed every five years.

In Australia, the CAPM is heavily relied upon when setting the ROE component of the cost of capital. While in most instances the regulatory commissions focus on the overall cost of capital (as opposed to separately reporting the debt and equity returns, along with the capital structure), it is possible to apply the CAPM to calculate the implicit ROE utilizing the given parameters, as provided in Table 4.

Netherlands

In the Netherlands, there are 12 regional gas network companies, the vast majority of which are owned by municipalities. Gas distribution companies' rates are subject to price caps, with annual adjustments for inflation and changes in productivity. The Netherlands employs a "yardstick regime", whereby each company's rates for an upcoming period are dependent on overall industry averages for items such as costs and quality of service. The most recent price cap period in the Netherlands was for the period 2005 through 2007. The Netherlands Competition Authority ("NCA") released a report in December 2005 detailing the NCA's proposed methodology for setting the cost of capital for the next price cap period. In that report, the NCA stated, "the price cap to promote operational efficiency has the aim, amongst others, of ensuring that network managers in any event cannot obtain a return which is higher than that which is usual within the economy and ensuring that equivalent efficiency is promoted amongst network managers."[3]

In the Netherlands, the ROE component of the allowed cost of capital, as proposed by the NCA, is determined using the CAPM methodology. In its report, the NCA suggested a range of values for the various inputs of the CAPM, including an equity risk premium of between 4.0 percent and 6.0 percent, a Beta of between 0.47 and 0.74, and a risk-free rate of 3.8 percent to 4.3 percent, based on ten-year government bonds. Interestingly, in developing the Beta estimate, the NCA used a proxy group of comparison companies that included

[3] Netherlands Competition Authority, "Consultation Document on the Cost of Capital for Regional Network Managers," December 2005, at p. 6.

Australian, Canadian, Spanish, U.K., and U.S. companies. The resulting range of ROEs is provided in Table 4 to this report.

IV. COMPARISON OF ROE METHODOLOGIES AND AWARDS

Discussion of ROE Methodologies:

Methodological approaches differ in determining ROE, but the primary drivers of investor returns (interest rates and risk) are represented in each alternative methodology. While the scope of this report does not include an analysis of the merits or appropriateness of each methodology, it is useful to understand the differing influences of alternative methodologies. Ideally, alternative methodologies would yield comparable results. However, some methods are more influenced by certain economic and business specific factors than others. For example, the DCF approach is the predominant approach for setting ROEs in the U.S. Under this approach, the ROE is determined by adding the expected dividend yield to the long term projected growth in dividends. That formula is the functional equivalent of the rate of return on equity, which when used to discount the expected cash flows associated with stock ownership (*i.e.*, the receipt of dividends in perpetuity), yields the current stock price (typically measured as an average over a reasonable period of time). Under the DCF approach, therefore, the ROE result is a function of annualized dividends, current stock prices, and anticipated long term growth.

The CAPM is a risk premium approach that specifies the required ROE for a given security as a function of the risk free rate of return, plus a risk premium that represents the non-diversifiable (sometimes referred to as "systematic") risk of the security. Non-diversifiable risk represents the variability in returns of a given security due to the combined macroeconomic forces in the economy. The fundamental notion underlying the CAPM is that risk adverse investors will require higher returns for assuming additional risk. This non-diversifiable risk is measured in terms of a company's Beta, or the covariance of the subject company's return relative to the broader market. Beta, therefore, is a measure of the extent to which the Company's returns are influenced by the same macroeconomic risks as the broader market, and thus can not be reduced by diversification. The CAPM formula is given by the following equation:

$$k_e = r_f + \beta (r_m - r_f)$$

The risk premium (r_m - r_f) portion of the CAPM is generally determined by subtracting the historical risk free rate from historical market returns.[4] The resulting ROE derived by the CAPM approach is driven by the current level of interest rates and the historical relationship between equity returns and risk free investments for the broader market.

An alternative equity risk premium approach is generally a statistically derived measure of the linear historical relationship between interest rates and the equity risk premium for the specific industry sector. Generally, for regulated utilities, this risk premium is calculated as the difference between authorized returns and the prevailing corporate or risk free bond yield. Using a corporate bond rate, the risk premium and recommended ROE would be given by the following formulas.

$$RP = a + (X_{RP} \text{ x } b_c), \text{ and}$$

$$k_e = b_c + RP$$

Where:

- RP = the risk premium
- a = the constant term in determining the risk premium, derived using an ordinary least squares regression model
- X_{RP} = the slope coefficient for the change in risk premium for a given change in the bond yield (this is generally negative indicating an inverse relationship), and
- b_c = the corporate bond yield.

As this formula indicates, the risk premium is a function of interest rates. Generally, as can be observed in U.S. and Ontario data, the risk premium decreases as interest rates increase. The resulting impact on ROE takes into account both the change in interest rates and the effect on the risk premium. With the typical estimation of this model, as interest rates change, the ROE changes by only a fraction of the change.

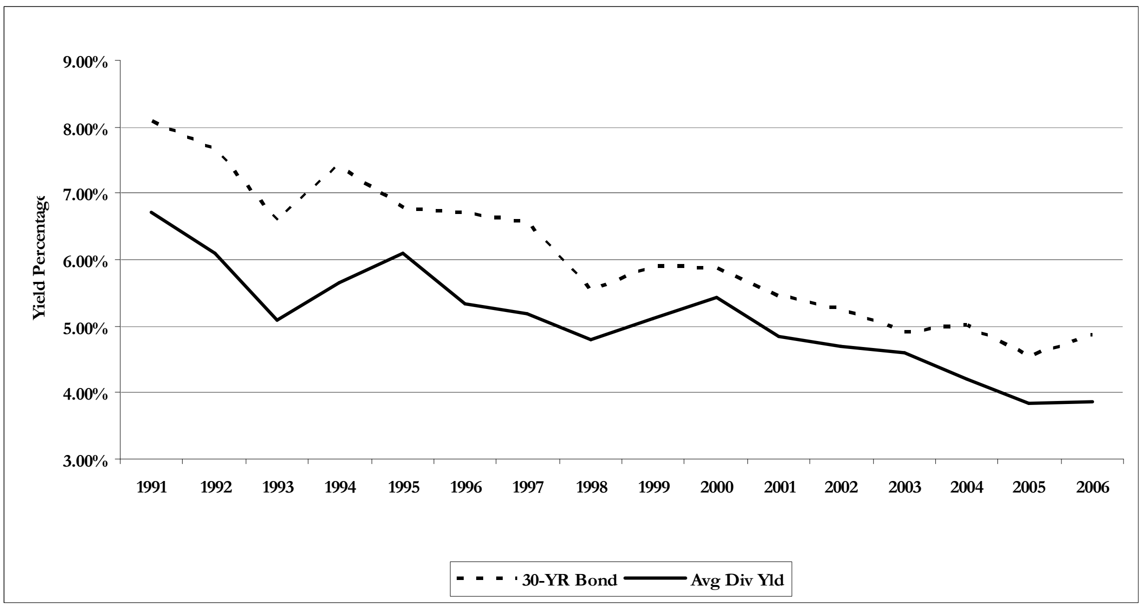
To understand why ROEs resulting from the DCF method might differ from a risk premium approach, such as the mechanism employed by the OEB, or a CAPM or other

4 It should be noted that the determination of the market equity risk premium is a hotly contested subject among experts and academics. There are several competing theories as to what the appropriate forward looking equity risk premium should be.

alternative equity risk premium approach, it is important to understand the relationship between utility dividend yields and bond yields.

There is significant academic research that establishes that utility stock prices are inversely related to the level of interest rates, and likewise that dividend yields and the level of interest rates are positively correlated. Chart 1 depicts the strong positive relationship between average annual 30-year U.S. Treasury yields and the average annual dividend yields for a representative group of U.S. gas distribution utilities.

CHART 1: COMPARISON OF U.S. GAS UTILITY DIVIDEND YIELDS AND U.S. 30-YEAR BOND YIELDS FOR THE PERIOD 1991 – 2006[5]



This strong positive relationship is attributed both to the capital (and debt) intensive nature of a utility, such that a decrease in debt capital costs will result in higher earnings and higher stock prices (lowering dividend yields), and to the fact that utilities' equity returns compete with debt yields in capital markets, as utilities are generally considered among investors to be relatively stable, lower risk investments.

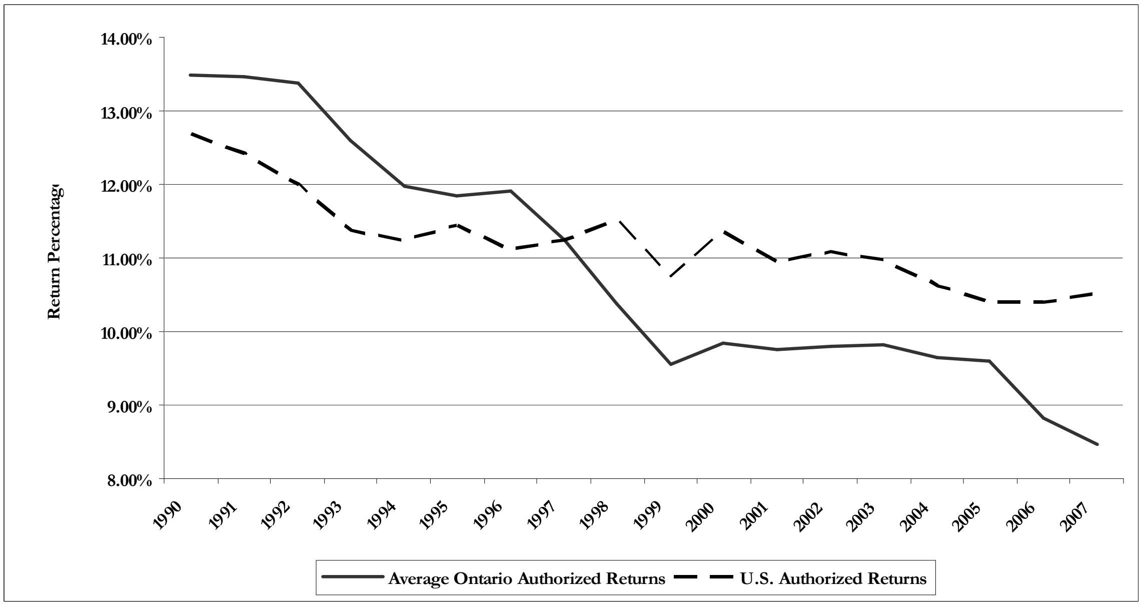
5 Dividend yields are represented for the average of all 15 natural gas distribution utilities covered by the Value Line Investment Survey's March 16, 2007 publication. 30-Year Treasury bond yields obtained from Yahoo! Finance.

There is a measurable relationship between the utility equity risk premium and the prevailing bond yield. With this typical relationship, as interest rates rise utility stock prices tend to fall and, accordingly, dividend yields rise. When stock prices behave in accordance with their historical behavior to movements in interest rates, the DCF methodologies and the risk premium methodologies will yield comparable results. However, stock prices and growth rates do not always move in accordance with historical norms, relative to interest rates, which creates differences between historical risk premium methodologies and the DCF approach. Economic factors that affect the utility sector, but not the broader market, such as stock price inflation due to speculation of merger and acquisition activities, or conversely, a sector-specific credit contraction such as that which occurred during the Enron bankruptcy, would yield a much different DCF result than that of an alternative risk premium approach. In short, the DCF approach is influenced to a substantial degree by industry specific factors that are reflected in stock prices, but are not accounted for by the level of interest rates.

Comparison of U.S. and Ontario Risk Premium Models

U.S. authorized returns and Ontario authorized returns were virtually in parity at the time the OEB implemented the ROE adjustment mechanism in 1997. Subsequently, U.S. and Canadian bond yields have declined significantly, and correspondingly the respective authorized returns declined as well. For example, the Canadian Long Bond yield decreased from 10.69 percent to 4.18 percent from 1990 to 2007, a difference of 651 basis points. The U.S. 30-year Treasury yield decreased from 8.62 percent to 4.81 percent, for the same period, a drop of 381 basis points. As shown in Chart 2, the more exaggerated decline in the Canadian Long Bond yield, coupled with the greater interest rate sensitivity of the OEB's ROE adjustment mechanism (discussed in further detail below), has led to a greater drop in Canadian authorized returns relative to U.S. authorized returns.

CHART 2: U.S. AUTHORIZED RETURNS VS. ONTARIO AUTHORIZED RETURNS – GAS DISTRIBUTION UTILITIES 1990 - 2007[6]



The OEB mechanism for adjusting ROE is most closely related to the previously described risk premium approach. By definition, the adjustment factor of 0.75 for a given change in interest rates implies that Ontario authorized ROEs are highly correlated to changes in bond yields and that the risk premium moves inversely to interest rates by a factor of 0.25 (1 - 0.75). Table 1 shows an illustrative example of how the OEB formula is applied.

6 Authorized return data for the Ontario Utilities was provided by the respective Ontario utilities. Return data was available for Union Gas and Enbridge from 1985-2007. Return data was available for Centra from 1990-1997, prior to its consolidation with Union in 1997. Average annual U.S. authorized return data was available for the period 1990-2007, per RRA Associates, through the SNL database.

TABLE 1: MOST RECENT ROE AWARDS FOR ONTARIO GAS UTILITIES

	OEB Adjustment Mechanism
Allowed ROE for test year 1	9.78%
Test Year 2 Long Canada forecast (30-year)	4.00%
Test Year 1 Long Canada forecast (30-year)	5.00%
Change in Interest Rates	-1.00%
Adjustment Factor/Slope Coefficient	0.75
Adjustment to ROE	-0.75%
ROE for Test Year 2	9.03%

An analysis of historical authorized returns in Ontario prior to the implementation of the ROE adjustment formula (from 1985 through 1997), reveals that authorized returns exhibited greater sensitivity to changes in interest rates than the currently prescribed 0.75 adjustment factor inherently assumes.[7] In the U.S., the risk premium has been more sensitive to changes in interest rates such that ROEs themselves are less affected by changes in long-term interest rates.

To understand the historical relationship of long term bond yields and authorized returns in the U.S. and Ontario, a series of regressions were performed on Ontario and U.S. data, using similar parameters. The first regression described the relationship of the risk premium for regulated utilities as a function of prevailing long term bond yields. The annual risk premium was derived by subtracting the annual average long term bond yield from the concurrent average authorized return. The second regression model described the relationship of the respective authorized return (as opposed to the risk premium) as a function of the prevailing long term bond yield. The time period reviewed for the Ontario utilities was prior to the OEB's implementation of its mechanical ROE formula, from 1985 to 1997. This time period was selected in order to characterize the relationship of Ontario authorized returns and bond yields, without respect to the returns produced by the adjustment mechanism

7 Prior to 1997, per the Board's "Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities", at page 2, ROE for gas distributors in Ontario was set much the same as it is in the U.S. today, through rate proceedings. In the rate proceedings leading up to the "Draft Guidelines" issuance, "experts relied principally on [the equity risk premium approach], followed by [the comparable earnings approach] and then DCF. The CAPM is typically given the least weight, if it is relied on at all." [Clarification added].

subsequent to 1997. Similar analyses were performed on U.S. data, although the time period selected for the U.S. models was from 1990 to 2007. Though the autocorrelation present in these data sets would prohibit the inference of the impact on ROE of a given change in bond yields (at a 95 percent confidence level), the results do provide descriptive insight as to the historical relationship between interest rates and authorized returns in each market.[8] The results of these regression models are provided in Table 2:

TABLE 2: REGRESSION RESULTS – RISK PREMIUMS AND AUTHORIZED RETURNS AS A FUNCTION OF BOND YIELDS – ONTARIO VS. U.S.

	Intercept	t-stat$_\alpha$	X	t-stat$_x$	R^2
Risk Premium Regression Model = Intercept + (X * bond yield) = Risk Premium					
Ontario Data from 1985 – 1997	0.0546	3.1822	-0.1383	-0.7402	0.0474
U.S. Data from 1990 – 2007	0.0838	22.2059	-0.5365	-8.8984	0.8214
Authorized Return Regression Model = Intercept + (X * bond yield) = Authorized Return					
Ontario Data from 1985 – 1997	0.0546	3.1822	0.8617	4.6132	0.6593
U.S. Data from 1990 – 2007	0.0838	22.2059	0.4635	7.6862	0.7869

As the regression results illustrate, both the U.S. and the Ontario risk premiums reflect negative coefficients implying that changes in the risk premium have been inversely related to changes in interest rates. However, the Ontario risk premium coefficient is associated with a low level of statistical confidence. The Ontario risk premium coefficient is informative, however, in that it has a much weaker relationship to interest rates than is the case in the U.S., *i.e.*, -0.14 (and insignificant) in Ontario versus -0.54 in the U.S.

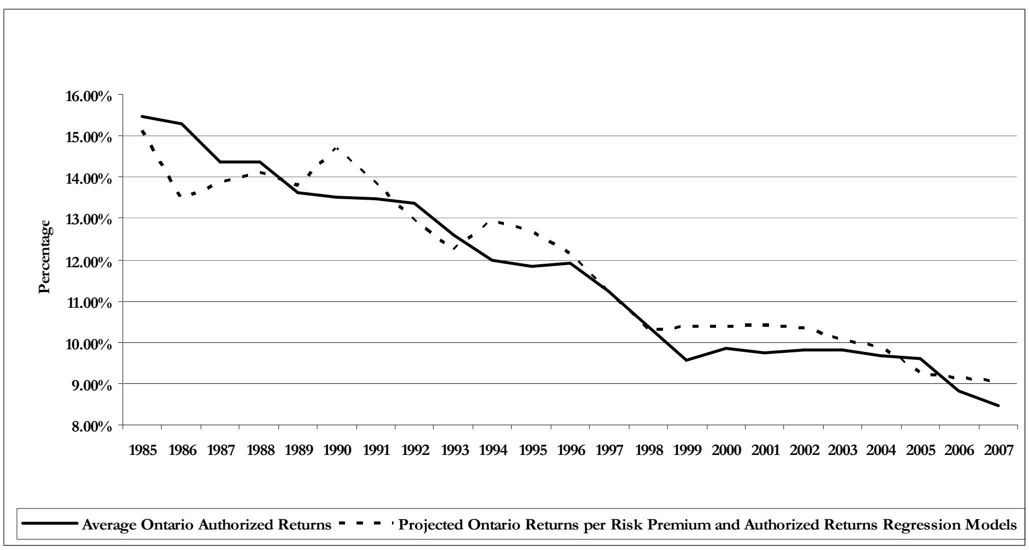
While the Ontario risk premium appears to have a much weaker link to interest rates than in the U.S., the Ontario authorized returns appear to have been more sensitive to interest rate fluctuations than in the U.S. The regression results above imply differences in interest rate sensitivity of the two models in that the variable coefficient for interest rates in the Ontario

8 *See* Plane and Oppermann, Business and Economic Statistics, Revised Edition at 395, where the authors state: "…There is one particular difficulty that arises in the analysis of time series that limits many of the techniques of statistical inference …. The difficulty is that the individual observations in a time series often depend on previous observations….This phenomenon, called serial correlation, causes most time series to be descriptive rather than inferential."

model is 0.86 where as the U.S. coefficient is 0.46. (That is, for every one percentage point change in interest rates, the Ontario ROEs change by 86 basis points while U.S. ROEs change by 46 basis points).

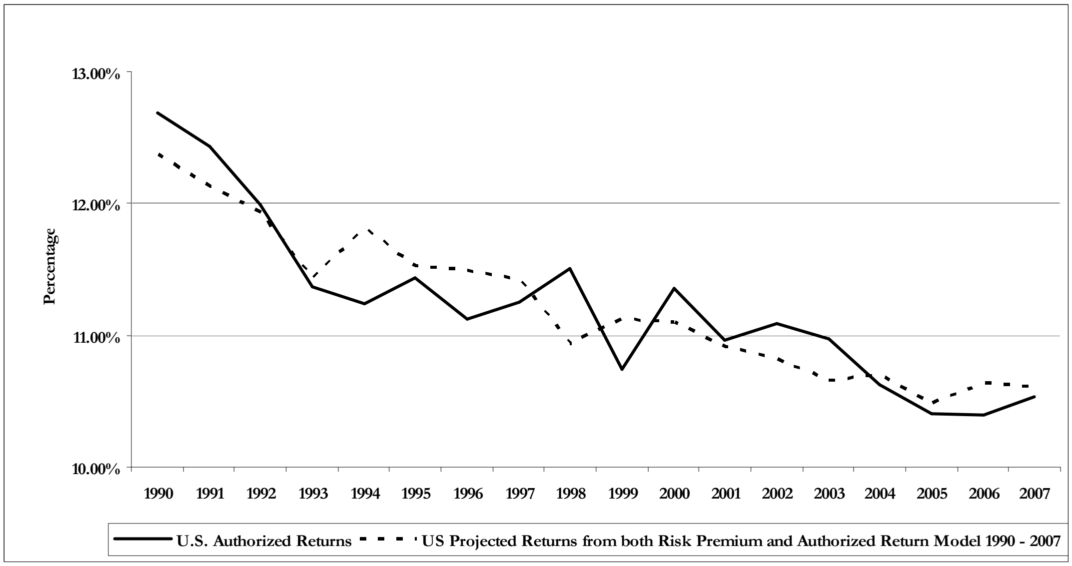
To assess whether the above regression models are informative in projecting authorized returns, CEA back-tested each of the models against actual data. Below are graphs for the U.S. and Ontario authorized returns that compare the actual returns to the estimated returns based on the respective Ontario and U.S. regression models. Charts 3 and 4 illustrate this comparison, showing that both regression models reasonably describe respective U.S. and Ontario authorized return issuances by the level of long term government bond yields, and may be informative in estimating the level of returns that would typically be authorized in each country for a given level of interest rates.

CHART 3: AVERAGE ONTARIO AUTHORIZED RETURNS VS. PROJECTED RETURNS PER REGRESSION MODEL – GAS DISTRIBUTION UTILITIES 1985 - 2007[9]



9 Authorized return data for the Ontario Utilities was provided by the respective Ontario utilities. Return data was available for Union Gas and Enbridge from 1985-2007. Return data was available for Centra from 1990-1997, prior to its consolidation with Union in 1997. Canadian Long Bond data was obtained from the Bank of Canada.

CHART 4: AVERAGE U.S. ACTUAL AUTHORIZED RETURNS VERSUS PROJECTED RETURNS PER REGRESSION MODEL 1990 - 2007[10]



To summarize, the OEB's factor of 0.75 used in its automatic ROE adjustment mechanism is reasonably close to what the above analysis on Ontario data suggests is the historical relationship between Canadian Long Bonds and gas utility authorized returns. Specifically, the above analysis suggests these variables are historically correlated by a factor of 0.86 in contrast to the 0.75 used in the OEB adjustment formula. These results differ markedly from the model describing U.S. data, which suggests a coefficient between authorized returns and interest rates of 0.46. The reason for the difference between the Ontario coefficient of 0.86, implied by the regression model, and the historical U.S. implied factor of 0.46, is subject to speculation, but may be due in part to Canada's historical reliance on the risk premium approach in establishing authorized ROEs, as well as the use of a test year and less frequent ROE determinations in the U.S. (as opposed to the more frequent ROE determinations in Ontario). However, the difference in the interest rate sensitivity explained by the U.S. regression model and the Ontario adjustment mechanism at least partially explains the recent disparity between U.S. authorized returns and Ontario authorized returns. As interest rates have declined dramatically in Canada in the past ten years, one would expect the OEB formula to yield accordingly lower authorized ROEs.

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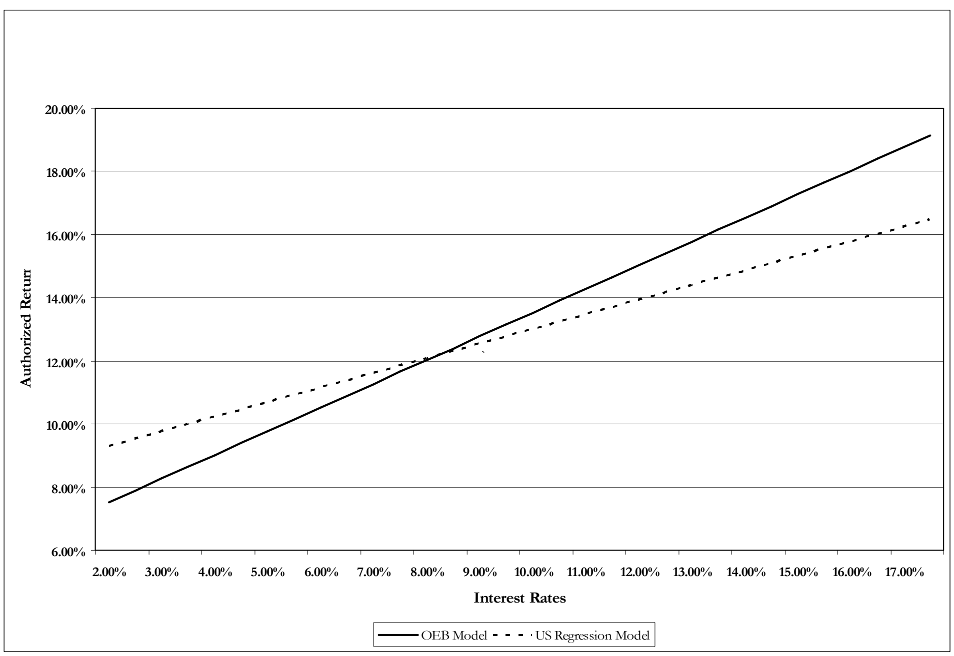
[10] U.S. authorized return data was available from 1990 to 2007, per RRA Associates, through the SNL database. 30-Year Treasury yield data was obtained from Yahoo! Finance.

The formula, however, is symmetrical, and ROEs will most likely recover at a faster rate in Ontario than in the U.S., when interest rates begin to rise. In fact, if interest rates continue to steadily rise, the OEB adjustment formula could surpass and yield higher results than historical data suggest U.S. authorized returns would reach under the same circumstances. Below is a sensitivity analysis between U.S. authorized returns per the above regression model and the OEB adjustment formula. As Chart 5 illustrates, there is a greater difference between U.S. and Ontario returns at extreme high and low interest rates. It is important to note, however, that over the range of interest rates from 4.00 percent to 6.00 percent (a range of projected rates that is within the bounds of consensus forecasts), the OEB model yields results that are consistently and significantly below those implied by the U.S. regression model.

CHART 5: SENSITIVITY ANALYSIS – ROE DETERMINED BY OEB FORMULA VS. U.S. REGRESSION MODEL OF AUTHORIZED RETURNS EXPLAINED BY 30-YEAR TREASURY BOND YIELDS[11]



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11 Chart 5 assumes the U.S. and the Canadian long term government bond yields are in parity. U.S. authorized returns are calculated based upon the regression equation, k= 0.0838 + (0.4635 x *i*). The OEB adjustment formula assumes that the formula would yield a return of 12.25 percent when long Canada bond yields are 8.30 percent, as was the case when the mechanism was first proposed. The OEB model formula takes the change in the Canadian Long Bond for the period x 0.75, plus the previous return, so that when interest rates are at 8.30 percent, the ROE is 12.25 percent.

Quantification of Inter-jurisdictional Differences in ROE:

Beyond the methodological differences addressed in the prior section, the OEB requested that CEA examine other factors that explain differences in ROEs between Ontario and other jurisdictions. CEA began this portion of the analysis with the premise that a reasonable and practical benchmark against which to compare allowed ROEs in Ontario is a range of recently authorized ROEs for other gas distribution utility companies both in Canada and abroad. While there are a multitude of jurisdictional and company-specific business, operating, financial, and regulatory risks that must be taken into consideration when evaluating individual utility ROEs and estimating the equity returns expected by investors, CEA believes the ROEs awarded by a broad base of other regulatory commissions can form an adequate starting point for comparison.

To begin its analysis, CEA gathered data from approximately 50 different rate cases in Canada and the U.S. from 2005 to the present, including: (1) the utilities receiving the ROE awards and the jurisdictions in which they operate; and (2) the authorized ROEs and capital structures. CEA also gathered summary level data regarding ROE methodologies and allowed returns in the U.K., Australia, and the Netherlands. A summary of this data is presented in Tables 3, 4, and 5, and detailed information for all the Canadian and U.S. companies studied can be found in Exhibit 1. As discussed in greater detail later in this report, CEA narrowed the U.S. group of companies to a subset of companies more comparable to the Ontario gas distributors on the basis of size, degree of non-gas distribution (*e.g.*, electric or steam) operations, and credit rating (see the "Revised Comparison" discussion in this section of the report for a discussion of the process used to limit the population of U.S. companies to a more comparable group). The results for these eight companies are also presented in Table 4.

TABLE 3: MOST RECENT ROE AWARDS FOR ONTARIO GAS UTILITIES

Utility	2006 ROE/Equity Ratio	2007 ROE/Equity Ratio
Enbridge Gas Distribution	8.74% / 35.00%	8.39% / 35.00%[12]
Union Gas	8.89% / 35.00%	8.54% / 36.00%

12 Per Enbridge Gas Distribution Inc.'s 2006 Annual Information Form, the company has requested an equity percentage of 38 percent in its pending 2007 rate application.

Table 4: Most Recent ROE Awards for Gas Utilities in Other Jurisdictions

Jurisdiction	Utilities Receiving Recent ROE Awards	Average ROE /Equity %[A]	Primary Method for Setting ROE	Adjustment Mechanism
Canada				
British Columbia (PNG and Terasen)	5	8.85% / 37.40%	ERP/DCF[B]	Annual Adj.
Gaz Metropolitain – Québec.	1	8.95%[C] / 38.50%	CAPM/ERP[D]	Annual Adj.
Alberta (ATCO and Alta)	2	8.51% / 39.00%	CAPM[E]	Annual Adj.[F]
Canada (average)[G]	8	8.78% / 38.00%		
United States (average)	34	10.35% / 48.00%	DCF[H]	Case-by-Case
United States (average of 8 comparable cos.)	8	10.40% / 46.44%	DCF	Case-by-Case
U.K (estimated)[I]	4	6.25%[J] / 37.50%	CAPM	Fixed (5 Year Period)
Australia (estimated)[K]	8	11.70% - 12.70% / 40.00% - 45.00%	CAPM	Fixed (5 Year Period)
Netherlands (estimated)[L]	12	7.00% / 40.00%	CAPM	Fixed (3-5 Years)

<u>**Notes to Table**</u>:

[**A**] ROE award based on most recent award for applicable utilities.

[**B**] *See*, British Columbia Utilities Commission, "In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism," Decision, March 2, 2006.

[**C**] 8.95 percent for Gaz Met does not include an adder to ROE of 0.38 percent, which represents an incentive amount based on expected productivity gains. *See*, Gaz Métro Limited Partnership, Analyst Annual Meeting Presentation, December 13, 2005.

[**D**] Per a representative at Regie de L'Energie, ROE was last reviewed in decision D-99-11, R-3397-98, in which the "the Regie put most of the weight towards [the] Capital Asset Pricing Model and the Equity Risk Premium."

[**E**] In its 2004 Generic Cost of Capital proceeding, the Alberta EUB relied on the CAPM, using other ERP methodologies as a check on reasonableness. *See* Alberta EUB, Decision 2004-052, July 2, 2004.

[**F**] Changes in an ROE, while annual, only take effect if a utility files an application for a change in rates for the applicable test year. *See*, ATCO Ltd. 2006 Annual Information Form, at p. 8.

[**G**] CEA purposefully omitted certain other provinces in Canada due to a general lack of comparability. For example, Enbridge Gas New Brunswick, with an ROE award of 13.00 percent, was not included due to its status as a "developing" distribution company. The group of Canadian companies studied by CEA appears to be consistent with groups used in ROE regulatory proceedings and by analysts.

[**H**] In CEA's experience, jurisdictions in the U.S. often rely on the DCF model, using other methodologies to validate the DCF results. The FERC's favored approach is a form of the DCF model.

[**I**] Rates of return will be reset for the 2008-2014 period. The 6.25 percent ROE was recently re-affirmed for an additional year-long period, after it was set to lapse in 2007. In a recent discussion regarding the cost of capital for U.K. gas distributors, the Ofgem stated, "Since this is a one year control, and we have explained that we will review the cost of capital for the main control, we are not sending any signal regarding long-term returns, so long-term investment decisions should not be unduly affected." *See*, Ofgem, "Gas Distribution Price Control Review One Year Control Final Proposals," December 4, 2006, at p. 31.

[**J**] The "Vanilla WACC" (equal to the pre-tax cost of debt plus the after tax cost of equity, adjusted for capitalization), was set at 5.25 percent, with 62.5 percent debt and a cost of debt of 4.65 percent. The implied ROE is thus 6.25 percent after-tax.

[**K**] Australian price cap reviews are performed every five years. Based on the most recent price cap reviews in the states surveyed, the range of implicit nominal ROEs range from 11.7 percent in Victoria (based on an October 2002 review) to 12.7 percent in Western Australia (based on a June 2000 review). The average for this group is 12.1 percent. The regulatory commission of New South Wales provides a range of parameters for which the ROE can be calculated, resulting in an implicit ROE range of 10.1 percent to 12.2 percent.

[**L**] In its report, the NCA suggested a range of values for the various inputs of the CAPM, including an equity risk premium of between 4.0 and 6.0 percent, a Beta of between 0.47 and 0.74, and a risk-free rate of 3.8 percent to 4.3 percent, based on ten-year government bonds. The resulting range of ROEs (based on an equity percentage of 40 percent), is from approximately 5.7 percent to 8.7 percent, with an average of 7.0 percent. It is important to note that this range of ROEs is based on proposed parameters for the CAPM provided by the NCA.

TABLE 5: ROE AND EQUITY PERCENTAGE DIFFERENTIALS

	ONTARIO (AVERAGE OF ENBRIDGE AND UNION)	OTHER CANADIAN PROVINCES	U.S.	U.S. (8 COMPARABLE COMPANIES)
ROE	8.82% ('06) 8.47% ('07)	9.15% ('06) 8.77% ('07)	10.35% ('05 – present)	10.40% ('05 – present)
Ontario ROE Differential[13]	--	(.33%) ('06) (.31%) ('07)	(1.53%) ('06) (1.89%) ('07)	(1.58%) ('06) (1.94%) ('07)
Equity %	35.50% (2007)	37.94%	48.00%	46.44%
Ontario Equity % Differential	--	(2.44%)	(12.50%)	(10.94%)

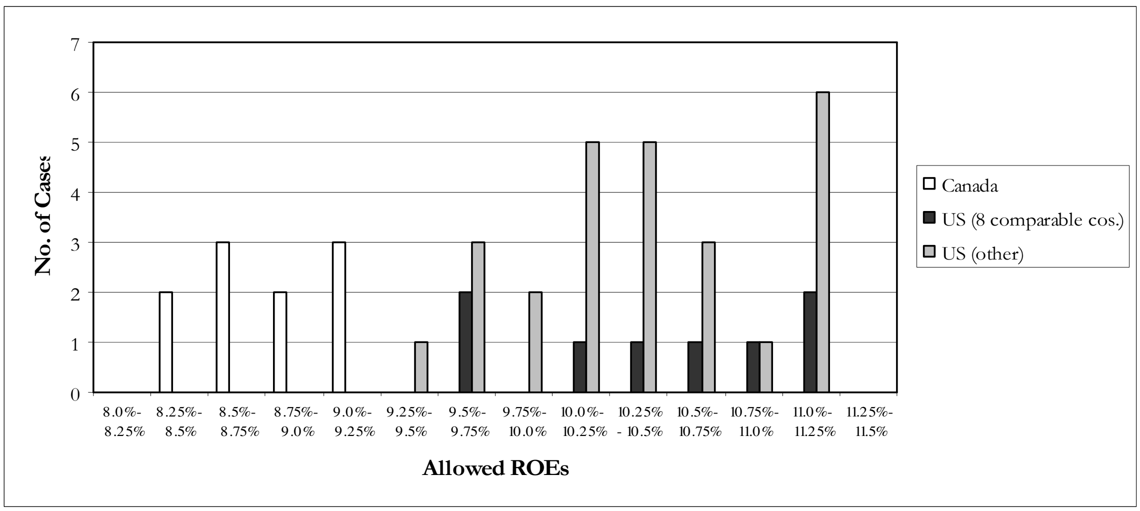
As can be seen in Table 5, the two major gas distribution utilities in Ontario have an average 2007 ROE of 8.47 percent, as compared to an average 2006 ROE of 8.82 percent. For the remaining provinces in Canada, the average ROE is 8.77 percent for 2007 and 9.15 percent for 2006. In the U.S., the overall average allowed ROE is 10.35 percent, and for a subgroup of more comparable U.S. companies (as discussed in more detail later in the report), the average ROE is 10.40 percent.

Chart 6 represents a histogram of allowed ROEs in Canada (for the five provinces studied) and the U.S. (for the group of eight comparable companies and for the remainder of the U.S. group). The two major gas distribution utilities in Ontario have 2007 ROEs of 8.39 percent for Enbridge, and 8.54 percent for Union, as compared to 2006 ROEs of 8.74 percent and 8.89 percent. For the remaining provinces in Canada, the ROEs range from 8.37 percent for Terasen's British Columbia operations to 9.07 percent for Terasen's Vancouver Island

13 Due to the fact that the majority of U.S. companies adjust their ROEs on a case-by-case basis, depending on the timing of their rate cases, as opposed to the annual adjustment mechanism in place in Ontario and other Canadian jurisdictions, CEA has presented comparisons of U.S. ROEs to both 2006 and 2007 allowed ROEs in Canada. The breakdown by year of the U.S. rate cases is as follows: 2005 – 20 rates cases, average ROE of 10.35 percent; 2006 – 11 rate cases, average ROE of 10.32 percent; 2007 – 3 rate cases, average ROE of 10.53 percent.

operations (a 70 basis point spread). In the U.S., the recently allowed ROEs range from 9.45 percent for CenterPoint Energy Resource's Arkansas operations, to 11.20 percent for two utilities in Wisconsin (a 175 basis point spread), with a mean of 10.35 percent, and a median of 10.40 percent. For a subgroup of more comparable U.S. companies (as discussed later in the report), the range is from 9.50 percent for Southwest Gas Corp. in Arizona to 11.20 percent for Wisconsin Gas (a 170 basis point spread), with a mean of 10.40 percent and a median of 10.46 percent.

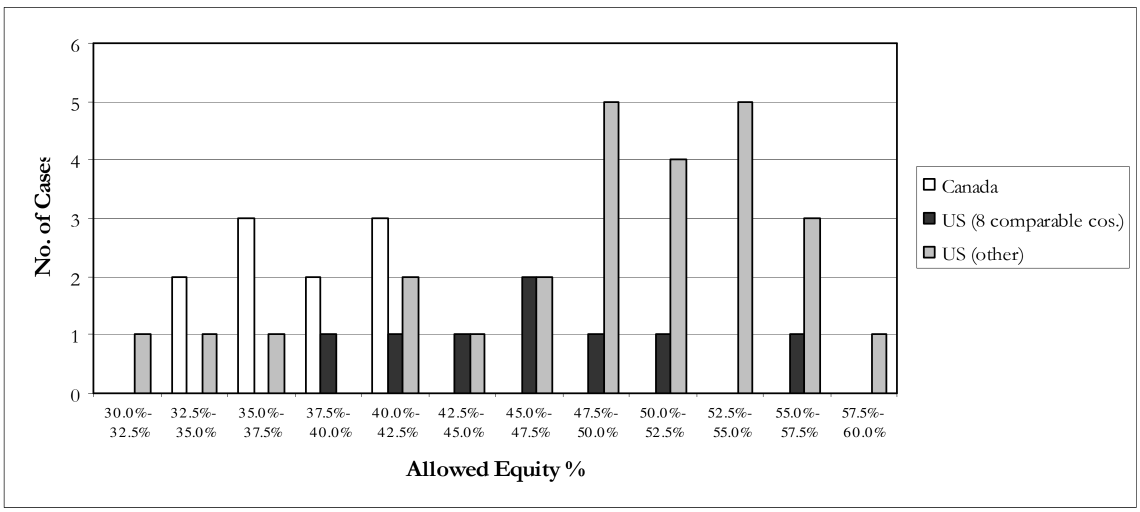
CHART 6: HISTOGRAM OF ALLOWED ROEs IN CANADA AND THE U.S.



As can be seen in Chart 6, there is no overlap between the ranges of Canadian and U.S. ROEs, with Canadian ROEs being fairly evenly distributed between 8.25 percent and 9.25 percent, and U.S. ROEs clustering between 10.00 percent and 10.50 percent, with the mode (eight of the 34 total cases) being 11.00 percent. It is important to note that while the Canadian and U.S. ROE ranges do not overlap, the ranges themselves are also quite different, in terms of spread from top to bottom (*i.e.*, the 70 basis point spread in Canada versus the 170 to 175 basis point spread in the U.S.). Possible reasons for this additional divergence are provided in the Jurisdictional Analysis discussion presented later in this report.

CEA also gathered data related to the allowed equity percentages of the companies analyzed. The allowed equity percentages in 2007 are 35.00 percent and 36.00 percent for Enbridge and Union, respectively, although Enbridge has requested a 38.00 percent equity ratio in its pending rate case. As shown in Exhibit 1, equity ratios in other Canadian provinces range from 37.00 percent to 39.00 percent, and those in the U.S. are 31.80 percent on the low end, for CenterPoint Energy Resource's Arkansas operations,[14] and 60.00 percent on the high end, for Wisconsin Public Service Corporation, with a mean and median of approximately 48.00 percent. The companies in the group of eight comparable U.S. gas distributors have equity percentages ranging from 39.31 percent for Michigan Consolidated Gas to 56.37 percent for Northern Illinois Gas, with a mean of 46.44 percent and a median of 46.77 percent. Summary level information is provided in Table 5, and Chart 7 shows the distribution of allowed equity percentages in Canada and the U.S.

CHART 7: HISTOGRAM OF ALLOWED EQUITY PERCENTAGES IN CANADA AND THE U.S.



While there is some overlap between the allowed equity ratios in Canada and the U.S., the Canadian equity ratios are narrowly gathered between 32.50 percent and 42.50 percent, while the U.S. equity ratios are well spread throughout the range, with the most instances between 47.50 percent and 55.00 percent.

Chart 8 presents a scatter plot of ROEs and equity percentages in Canada and the U.S.

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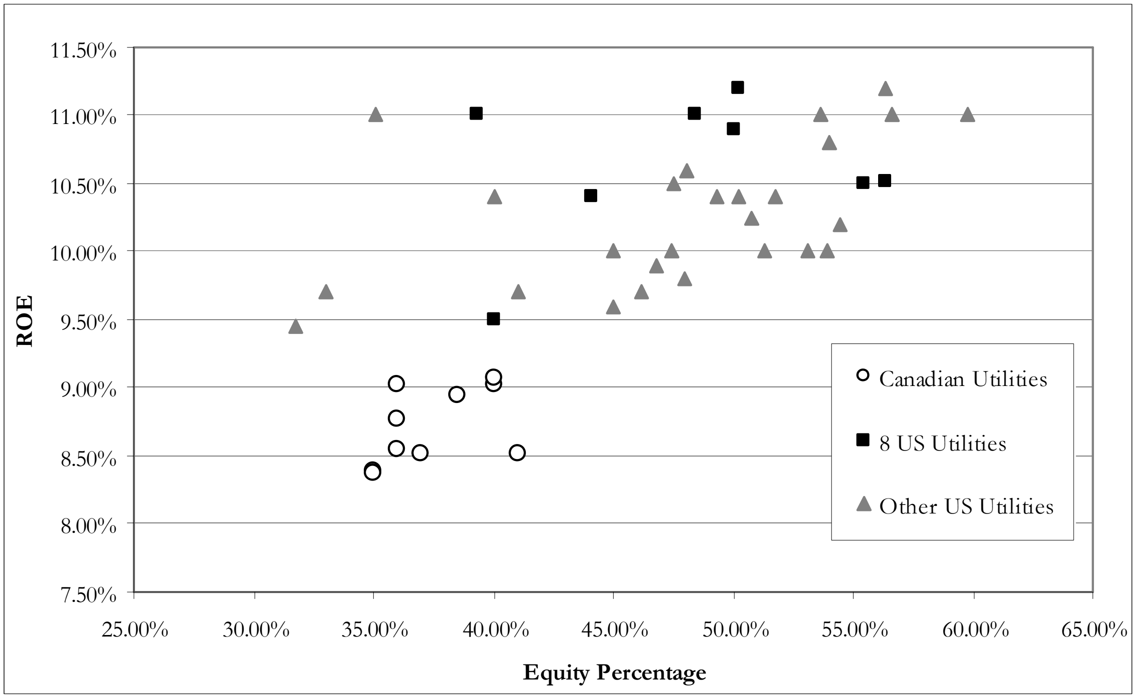
14 It is worthy to note that Arkansas uses the Modified Balance Sheet Adjustment, which is unique among U.S. regulatory jurisdictions.

CHART 8: SCATTER PLOT OF ALLOWED ROES VS. ALLOWED CAP STRUCTURE



While pictorially Chart 8 may suggest a positive relationship between ROEs and equity percentages that runs counter to expectations (as, in general, financial theory would suggest that as equity ratios decrease, the cost of equity increases), a closer look at the data suggests that no such conclusion can be drawn. Table 6 shows the regression results for Canada and the U.S., based on the data presented in Chart 8, illustrating that in Canada, there is not a statistically significant relationship between equity ratios and ROEs (based on a t-statistic of 1.51), while in the U.S., a statistically significant relationship exists, but with little explanatory value (based on an R^2 of .186).

TABLE 6: REGRESSION RESULTS COMPARING ROES TO EQUITY RATIOS

	Intercept	t-stat$_\alpha$	X	t-stat$_x$	R^2
Canadian Data	.065	4.44	.059	1.51	.222
U.S. Data	.088	14.87	.033	2.70	.186

Assessment of Inter-jurisdictional Differences in ROE:

The fact that a disparity exists between ROEs for gas utilities in Ontario and other jurisdictions, particularly the U.S., is not disputed. As stated earlier, the OEB requested that CEA seek to gain an understanding of why the difference exists, and if there is some explanatory justification beyond the methodology employed in Ontario versus other jurisdictions. As return on equity is a measure of the return that investors seek for a given amount of risk, the key question is:

> ***Are gas distribution companies in other jurisdictions more risky than those in Ontario, as would be indicated by higher ROEs applied to larger equity percentages, and visa-versa?***

A key issue is therefore assessing comparative risk. To perform this assessment, CEA gathered further data regarding fundamental operating, financial, regulatory and business risks for the companies that were included in the analyses discussed earlier in this report.

Company-Specific Data

Both Dominion Bond Rating Service ("DBRS") and Standard & Poor's ("S&P") cite a series of factors used to determine the business risk of an LDC.[15] Table 7 is a summary of the factors provided by these two ratings agencies.

[15] *See*, Dominion Bond Rating Service, "Rating Utilities (Electric, Pipelines & Gas Distribution)", March 9, 2005; Standard & Poor's, "Key Credit Factors for U.S. Natural Gas Distributors," November 2006.

TABLE 7: DBRS AND S&P BUSINESS RISK FACTORS

DBRS	S&P
• Regulatory factors • Competitive environment • Supply/demand considerations • Regulated vs. non-regulated activities • Domestic vs. foreign operations • Capital spending program • Coverage ratios • Qualitative factors such as customer mix, economic strength in the service territory, and management expertise	• Regulation • Weather protection • Earnings sharing • Allowed ROE • Other regulatory factors • Financial protection from affiliates • Markets and competition (including service territory growth, saturation, customer mix, protection against bypass, and economic strength) • Factors related to supply, storage, system condition, and hedging • Management

Similarly, in developing a comparable, or "proxy", group of companies for the purposes of evaluating and estimating the required return on equity for utility companies, including gas distribution companies, various screening criteria and metrics of risk are used to arrive at a group of companies that are fundamentally comparable to the subject company. More specifically, when estimating the ROE for a regulated gas distribution company, such as Enbridge or Union, a combination of screening criteria typically is used by financial experts to identify utilities with similar business, financial, and regulatory risks. These criteria may include:

- *Similar Operating and Financial Characteristics*: The analyst uses companies that exhibit operating and financial characteristics similar to the subject company in that they have a specified percentage of regulated operations, and regulated natural gas operations contribute a majority of revenues and net income;

- *Credit Rating*: If the subject company is rated BBB- or above by Standard & Poor's, or a similar ratings agency, each selected company has senior bond and/or corporate credit ratings that are investment grade;
- *Beta*: The analyst may include only those companies with Betas that are within a reasonable range of the group average;
- *Customer Mix*: A concentration of customers in one particular class, such as large industrial customers, has certain risk ramifications, and thus customer mix by volume or revenue within certain ranges can assist in defining the proxy group;
- *Other*: Depending on specific details regarding the subject company and the environment in which it operates, other screens related to regulatory restructuring, geography, or other pertinent criteria may be employed.

While not all of this data is available for the companies studied, CEA gathered as much data as was publicly available along the lines discussed above. Beta, for example, is calculated using individual company stock returns as compared to the returns of a broader index. As the majority of the companies studied as part of this report are subsidiaries of larger corporations, no trading data is available at the subsidiary level, and thus Beta cannot be calculated.[16] In addition, where financial or other information was not available for companies in the study (for example, if the company were a small subsidiary for which no financial data were available), CEA used parent-level information, and applied it to the subsidiary based on reasonable assumptions of relative size.

CEA also recognizes the correlation between the size of a company and its investors' required returns. The financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect."[17] While empirical evidence of the size effect often is based on studies of industries beyond regulated

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[16] As an alternative, the Beta of a parent company may be used by a financial analyst as a proxy for that of a subsidiary in those cases in which the parent's operations are representative of the subsidiary's operations. However, in cases in which the parent has subsidiary affiliates with substantially different risk profiles (such as a holding company with a mix of regulated and unregulated subsidiaries), this approximation becomes less justifiable.

[17] *See* Mario Levis, "The record on small companies: A review of the evidence," *Journal of Asset Management 2* (March 2002):368-397, for a review of literature relating to the size effect.

utilities, utility analysts also have noted the risks associated with small market capitalizations. Specifically, Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[18]

Small size, therefore, leads to two categories of increased risk for investors: (1) liquidity risk (*i.e.*, the risk of not being able to sell one's shares in a timely manner due to the relatively thin market for the securities); and, (2) fundamental business risks. For this reason, CEA also gathered information for each company related the size of its operations. As the majority of the companies in our sample population are subsidiaries of larger corporations, all with differing types of regulated and unregulated affiliated companies, CEA could not gather market capitalization data, nor did we think applying an assumed market-to-book ratio to each of the companies would provide for a meaningful analysis. For that reason, CEA collected information related to book capitalization, total revenue, total customers, and gas throughput as proxies for the relative size of the individual companies.

CEA notes that the Board also requested that CEA gain an understanding of how varying degrees of forecasted capital expenditures might affect ROE. As this type of data is inconsistently available for the companies studied, it is difficult to perform a quantitative analysis from which any conclusions can be drawn. CEA has discovered in previous cases, however, that heightened capital requirements increase business risk for companies in several ways: (1) risk of cost under recovery associated with project cost over runs and/or poor performance of the new facilities; and (2) capital requirements to finance new construction can result in downward pressure on the Company's credit rating. Market data indicate that investors recognize these risks and discount the valuation multiples of companies with high ratios of capital expenditures to net plant. That is, the financial community acknowledges the risks associated with substantial capital expenditures and reflects those risks in lower valuation multiples, and therefore, higher required returns.

18 Michael Annin, "Equity and the Small-Stock Effect," *Public Utilities Fortnightly*, October 15, 1995.

In addition, as this is a study of *comparative* risk, as opposed to *absolute* risk, CEA has specifically not gathered information related to factors that by and large affect all gas utilities. For the most part, these factors include comparative costs between natural gas and other energy sources, as well as the effect of declining use due to improved efficiency in gas appliances and equipment.[19]

For Canadian companies, data was gathered from information provided by the OEB, Annual Information Forms and Annual Reports, company websites, and discussions with and documentation from company representatives and other market participants. In total, CEA studied ten Canadian gas utilities, including Enbridge and Union in Ontario, Gaz Metropolitain in Québec, three divisions of Pacific Northern Gas, Ltd. and two divisions of Terasen in British Columbia, and AltaGas Utility and ATCO in Alberta.

For U.S. companies, rate case and company data was gathered from the SNL Interactive database, the Regulatory Research Associates database, and company filings and websites. CEA studied 37 rate cases for 34 companies in 22 different states. For companies that had two or more decided rate proceedings in the past two years, CEA used the most recent proceeding for comparative purposes.

A full list of data sources is provided in Appendix B. The full data set of companies and rate proceedings is presented in Exhibits 1 and 2 to this report. A summary of the allowed ROEs is provided in Tables 4 and 5, and a summary of the remaining data is presented in Table 8.

19 CEA recognizes that cost competition and declining use may affect some utilities more than others. However, an in depth analysis of these factors is outside the scope of this report.

TABLE 8: COMPARISON OF OPERATIONAL AND FINANCIAL DATA[20]

Company/ Jurisdiction	Most Recent ROE	Allowed Equity %	% Regulated Rev./% Gas Distribution Rev.	Book Value (million $CAD)	Total Revenue (million $CAD)	Gas Distribution Revenue (million $CAD, 2006)	Total Gas Dist. Customers (millions)	Gas Volume Sold (billion cubic meters, 2006)	Customer Mix	Credit Rating (DBRS/ S&P)
Enbridge Gas Distribution	8.39%	35%	100%/98%	$4,779	$3,016	$2,958	1.8	4.4 dist 7.1 trans 11.6 total	Ind 5% Com 23% Res 47% Whls 2% Trans 23%	A/A-
Union Gas	8.54%	36%	100%/91%	3,442	2,079	2,046	1.3	13.2 dist 20.6 trans 34.0 total	Ind 12% Com 20% Res 7% Whls 0% Trans 61%	A/BBB+
U.S (average of 34 companies)	10.35%	48%	84%/36%	2,882	2,238	1,175	.6	3.3	Ind 15% Com 19% Res 42% Whls 2% Trans 22%	BBB+ (average S&P rating of utilities)
U.S (average of 8 comparable companies – see discussion below)	10.40%	46.44%	89%/60%	2,767	2,418	1,307	1.1	5.2	Ind 11% Com 20% Res 47% Whls 0% Trans 22%	BBB+ (average S&P rating of utilities)

20 As noted previously, certain data for the U.S. companies in the analysis are estimates based on data at the parent company or reporting segment level, allocated to the subject company based on a best estimate of the subject company's contribution to the overall parent or segment.

As a whole, based on the metrics presented above, the gas distribution companies in the U.S. can be seen to be largely comparable to Enbridge and Union. Notably, all of the companies in sample group, with the exception of Arkansas Western Gas Company, Consumers Energy, and Avista Corp. have investment grade ratings from S&P as of the writing of this report.

There are, however, a few notable differences between the Ontario utilities and those in other jurisdictions:

- *Size*: Enbridge and Union are comparatively larger than the majority of the other companies in the data set, when using total customers and total gas throughput as a basis of comparison, as well as book value.[21]

- *Diversification of Services and Non-regulated Affiliates*: Certain companies in the group have diversified operations, including electric operations and non-regulated operations. This is in contrast to Enbridge and Union, which are almost 100 percent regulated gas distributors. As noted by DBRS, "Companies that generate most of their earnings from regulated activities are typically more stable and predictable than those that have significant non-regulated operations."[22]

- *Approach to Setting ROE*: While ROE is an output of the rate-setting process, the approach used (formulaic versus case-by-case) may have some explanatory value in estimating investors' expected returns. In particular, there is some evidence from the market that the use of a formula for setting ROE provides for a more certain return (inasmuch as the only variable is the forecasted bond yield) than the case-by-case approach, regardless of the outcome of the calculation.

  For instance, S&P, in a review of Ontario's electric utilities, recently stated:

  > The stability, transparency, consistency, and timeliness of the Ontario regulatory regime and framework have been steadily improving as a result of ongoing amendments to the Ontario Energy Board Act…The OEB's decision to maintain its 1998 formula for determining ROEs

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21 For entities for which book value was not available (*i.e.*, subsidiaries of larger companies for which SEC reported financials are not available), CEA estimated book value by utilizing the book value of the parent company or reporting entity, and applying it to the subsidiary based upon an approximation of the subsidiary's relative size to the larger company.

22 Dominion Bond Rating Service, "Rating Utilities (Electric, Pipelines & Gas Distribution)", March 9, 2005.

> allowed for in the rate-setting process, while disappointing for equity holders and not likely to encourage privatization, is another example of stability and consistency."[23]

Inherent in these comments is the distinction between debt holders, who place significant emphasis on certainty, and equity investors, who are equally concerned with the adequacy of their return.

Additionally, in a presentation at a CAMPUT meeting in January of 2005, S&P cited regulatory clarity and certainty as affecting business risk and thus credit ratings.[24]

CIBC World Markets mirrored these statements in a recent research report on Spectra Energy Corporation, the parent of Union Gas. CIBC referred to Spectra overall as operating in a "stable" regulatory environment, and added, "Investments in Union Gas are low risk with capital cost and return on this capital pre-approved by the regulator. As such, we see Union Gas' regulated operations outside of storage as having a low earnings growth profile but a low-risk profile as well that generates stable cash flow."[25]

Thus, as shown above, market analysts look favorably upon regulatory certainty, but it should be noted that the predictability of authorized returns does not outweigh the necessity of an adequate return to attract needed capital.

- *Market Dynamics in Non-Canadian and Non-U.S. Countries*: While Canada and the U.S. are considered highly comparable, both economically and in terms of regulatory structure, there are fundamental differences in market dynamics

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23 Standard & Poor's, "Shining a Light on the Positive Outlooks for Ontario Electricity Distributors," March 26, 2007.

24 Standard & Poor's, "Attracting Capital – How Does Canada's Regulatory Environment Compare Internationally," CAMPUT Financial Seminar, January 14, 2005. It should be noted, also, that in the same presentation, S&P cited Canadian regulatory boards as a whole as providing for relatively more "consistency and predictability" than other countries' regulators, although Canadian regulators are, "slow to adapt to changes in external factors."

25 CIBC World Markets, "Spectra Energy Corporation, Attractive Energy Infrastructure Play; Commodity Headwinds a Near-term Issue," January 11, 2007.

in the other countries that CEA investigated (*i.e.*, the U.K., Australia, and the Netherlands). Whether it be regulatory framework (gas distributors in the U.K., Australia, and the Netherlands are currently operating under differing forms of price control regulation), ownership structure (the majority of gas utilities in the Netherlands are municipally owned, while all of the U.K. – approximately 22 million gas distribution customers – was until recently served by a single company, National Grid[26]), accounting rules, geography and climate, or other factors, the differing markets and regulatory environments in which these countries' gas distributors operate weaken the basis for comparison.

Revised Comparison

To further the analysis, CEA developed a more refined comparison group that could be considered to be more similar to Enbridge and Union based upon size and corporate structure (as measured by percentage of unregulated operations). By excluding certain less comparable companies, the resulting group could be considered to have business and operating profiles more similar to the Ontario utilities. It is important to note that the resulting group of eight "comparable companies" is not equivalent to a "proxy group" of comparable companies typically used in ROE analysis. In regards to the latter, in estimating the ROE for a company, a group of publicly-traded companies displaying similar characteristics to the subject company is analyzed using one or more of the approaches discussed above (*i.e.*, the DCF, CAPM, etc.) to develop a range of reasonable ROEs. In this case, however, we are beginning with a group of companies for which the ROE has already been estimated (*i.e.*, the allowed ROE), and then narrowing that group down to a subset of companies that are comparable to Enbridge and Union, based on certain criteria. Due to the fact that the data set is highly dependent on which companies have been awarded ROEs in the recent past, and also contains a large number of subsidiary companies for which accurate

26 The current cost of capital in the U.K. was established in 2000/2001. In 2005, National Grid divested a large portion of its operating segments, cutting National Grid's distribution segment in half. The U.K. gas distribution price control, along with the associated cost of capital, however, was kept in place for the legacy companies. The fact that the cost of capital was set under a significantly different market structure, and is currently under review in the U.K., may indicate that the allowed ROE in the U.K. is not indicative of current market dynamics.

financial and operational data is unavailable, it can not be expected that this "comparables group" would yield definitive ROE results against which to benchmark Enbridge and Union's allowed returns. The purpose of this analysis, therefore, is not to provide an implied range of reasonable ROEs to apply to Enbridge and Union, but rather to more accurately quantify the existing difference in allowed ROEs.

This group of eight companies met the following criteria:

(1) Either between 500,000 to 2,200,000 gas distribution customers, or between three to approximately ten billion cubic meters in annual gas throughput (or both);

(2) Gas operations contribute at least approximately 40 percent of total revenues;

(3) A minimum BBB- (*i.e.*, investment grade) credit rating from S&P; and

(4) The companies currently have no earnings sharing mechanism in place. Similar to Enbridge and Union, therefore, shareholders are at risk for any deficiency in earnings below the allowed return, but also get to keep any amount exceeding the return.

Based on these screening criteria, the narrowed group of U.S. utilities contained the following companies[27]:

- Southwest Gas Corp. (Arizona)
- Atlanta Gas Light Company (Georgia)
- Northern Illinois Gas Company (Illinois)
- Michigan Consolidated Gas Company (Michigan)
- CenterPoint Energy Resources (Minnesota)
- Public Service Electric Gas (New Jersey)
- Puget Sound Energy, Inc. (Washington)
- Wisconsin Gas LLC (Wisconsin)

27 With the exception of Atlanta Gas Light Company, all the companies in the narrowed group entered into their most recent rate proceeding under their own volition, generally seeking increases in rates. Atlanta Gas Light Company had a three-year performance-based ratemaking ("PBR") mechanism in place for the period of 2002 to 2005, after the expiration of which it was required to file a rate case. The PBR plan was not re-authorized.

The resulting ROE from this revised group is 10.40 percent with a 46.44 percent equity ratio, as shown in Table 9.

TABLE 9: MOST RECENT ROE AWARDS FOR U.S. GAS UTILITIES

Sample Group	2007 ROE
Entire Group of 34 U.S. Companies	10.35% / 48.00%
Revised Group of 8 U.S. Companies	10.40% / 46.44%

Conclusion Regarding Company-Specific Data

The first conclusion that can be drawn from the comparison of financial and operational profiles of gas distribution companies in Canada and the U.S. is that there are many similarities between these two groups of companies (*i.e.*, Canadian and U.S. gas distributors), and the ranges of sizes, types and number of customers, and credit ratings largely overlap. The largest difference, as shown in Table 8, is in amount of gas throughput. Enbridge, a pure distribution company, has nearly double the average gas throughput for the eight U.S. comparable companies, and Union's distribution throughput is similarly greater than that of the U.S. group. However, while this is one measure of the size of the companies, based on other metrics of size, such as book value and total revenue, the groups can be seen to be similar, especially in a direct comparison of Union to the U.S. companies. In other words, it does not appear that the Ontario gas distributors taken together are notably less risky from the standpoint of business and operational risk, and any differences in the metrics studied above do not appear to justify the overall ROE differential.

The second conclusion that can be drawn stems from the fact that, when certain less comparable companies were excluded from the overall U.S. group, the average ROE remains essentially unchanged. What this tells us is that while the screening criteria employed are important in analyzing the risk of a regulated enterprise (for the reasons discussed earlier), the relative risk level of an individual utility is based on a combination of these and many other, sometimes subtle, differences in business and operating profiles.

In terms of the difference between Ontario gas distributors and other Canadian gas distributors, it is important to note that differences in allowed ROEs are largely a function of equity risk premiums set at various points in time over the last ten years, and are subject to different provincial regulatory environments and business risks.

Due to the fact that company-specific data do not appear to explain the gap between inter-jurisdictional ROEs, CEA expanded the analysis to include territory and country-specific factors, as discussed below. Specifically, CEA addressed: (1) differences in rate design and rate stabilizing mechanisms; and (2) macro-economic factors.

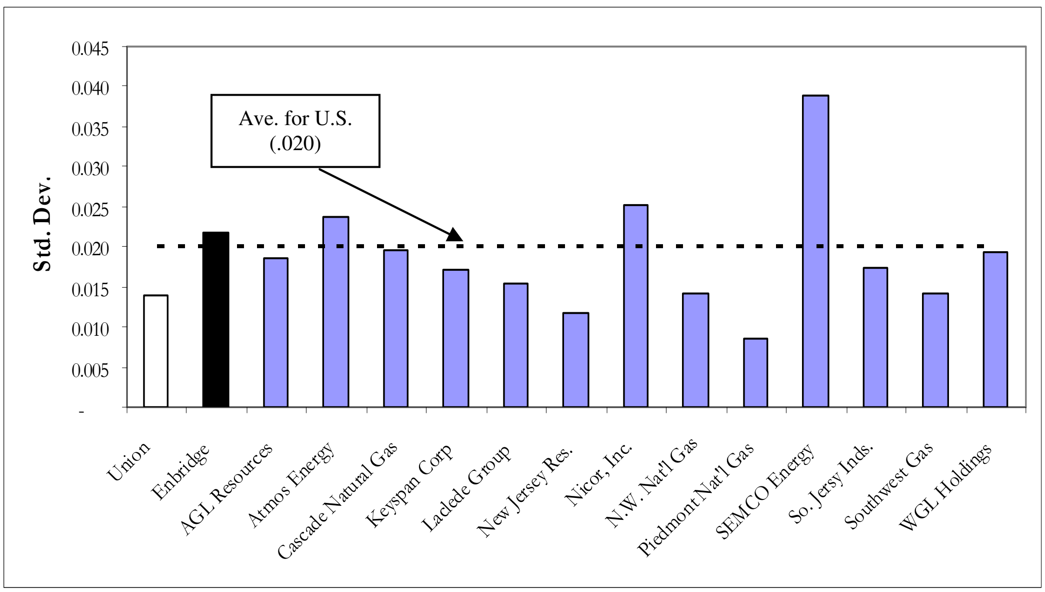
<u>Jurisdictional Analysis</u>

- *Rate Design and Rate Stabilization*: A common risk for gas utilities is under or over-recovery of revenue from ratepayers owing to changes in consumption, and variability in commodity costs. In addition, utility earnings can vary owing to these and other un-forecasted changes in revenues and costs. Across the companies studied as part of this report, there are many different forms of rate and cost stabilization mechanisms aimed at ensuring the utilities will be better able to earn forecasted revenues and recover forecasted costs. For example, some of the companies have weather normalization clauses that protect them from climatic variability; others are allowed to employ rate stabilization and cost deferral accounts to ensure rate and cost recovery.

  In a determination of the effect on earnings of different rate and earnings stabilization methods, weighing the various stabilizing mechanisms employed in the different jurisdictions against one another may not result in an "apples to apples" comparison, especially if all of the counterbalancing components of a company's rate design are not taken into account. Thus, to test whether the Ontario gas distributors have on the whole more stable earnings than their U.S. counterparts (and thus could be considered less risky), CEA analyzed recent earnings history for Enbridge and Union (as provided by the companies), as well as a group of U.S. gas utilities, to determine if there was a difference in variability in actual returns to equity holders.

As noted previously, there is not historical financial data readily available for the eight U.S. comparable companies since the majority of them are subsidiaries of larger holding companies. Thus, as a proxy for this group, CEA used the 15 gas utilities classified by Value Line as Natural Gas Distribution companies, as the required data is readily available. From this group, CEA removed two companies, Southern Union and UGI Corp., because they had relatively low percentages of gas operations as compared to total operations, and thus their earnings variability may be unduly affected by electric or other operations.[28] Chart 9 shows the variance in actual ROE for Enbridge, Union, and the 13 U.S. companies for the period 1997 to 2006.

CHART 9: ACTUAL ROE VARIABILITY FOR ONTARIO AND U.S. GAS DISTRIBUTORS, 1997 TO 2006



As shown in Chart 9, while the variability in ROE for the U.S. companies, as measured by the standard deviation in ROE, encompasses a large range of results (from .0084 to .0389), the average of .020, as measured by the square root of the mean variance, is not significantly different than that of Enbridge, while it is greater than that of Union. If SEMCO, a clear outlier, were to be removed from the U.S. group, the average would decrease to .018. Additionally, more than one-fourth of the U.S. companies (four of 13), fall at or below Union. Thus, while volatility in

[28] Southern Union reported, on average for 2005 and 2006, 36% of revenues and -11% of operating income to be earned from gas distribution operations. Similarly, UGI, on average over the past two years, derived only 11% of revenue and 17% of net income from their gas utility business.

earnings may affect the individual risk of U.S. utilities, or Ontario utilities for that matter, there is not a consistent difference across the markets that would explain the market-wide difference in average allowed ROEs.

As mentioned above, differences in volatility of actual ROEs between individual utilities can be attributed to a myriad of factors. These include but are not limited to: regulatory environment, revenue stabilization mechanisms (*e.g.,* weather normalization adjustments), operational environments, growth rates of territory and local economies, capital expenditures and associated uncertainties (*e.g.*, expansion projects), stability and significance of other business units, and corporate management.[29] The analysis performed above, as presented in Chart 9, was designed to account for the sum total of all of these factors on earnings, as opposed to weighing the individual influence of any one risk factor. For instance, in New Jersey, both New Jersey Resources and South Jersey Industries implemented conservation incentive programs in 2006, allowing the companies to promote energy conservation while insulating them from the negative impact of reduced customer usage (as a result of warmer weather, higher prices, or more efficient heating equipment, etc.). However, actual returns for New Jersey Resources decreased by 4.50 percent in 2006, from 17.00 percent to 12.50 percent, while those for South Jersey Industries increased by 3.90 percent, from 12.40 percent to 16.30 percent. Assuming the conservation incentive programs would have similar effects on each company's earnings, this difference in the directional movements of actual ROEs must be due to other factors. This demonstrates the need to analyze the overall effect of the many competing influences listed above in establishing the relative risk of a gas utility.

As noted above, the variability in earnings, measured by standard deviation, among the U.S. gas distributors in this analysis, ranges from 0.0084 (Piedmont) to .0389 (SEMCO). A similarly wide range of U.S. allowed ROEs was noted earlier in this

29 While ability to recover commodity costs would also influence earnings, it is CEA's understanding that these 13 U.S. companies studied, as well as Union and Enbridge, all have at least some form of gas cost recovery mechanisms in place.

report. This may be explained in part by differences in approach to ROE setting in the U.S. versus Canada. Generally, U.S. commissions rely on the qualitative aspects of the rate proceeding, as well as quantitative aspects. Moreover, the lesser frequency of rate proceedings in the U.S. often requires consideration of the projection of capital requirements beyond one year in determining ROE. This is in contrast to the approach most widely used in Canada, whereby ROE is adjusted annually based on a purely quantitative calculation.

Economic Analysis

- *Tax Law*: Tax law can play a role in investors' expected returns, particularly as it relates to the taxation of dividends. This is especially true for utilities, as they typically have relatively high dividend payout ratios. Canada and the U.S. have varying degrees of favorable tax rates or tax credits related to dividend payments to individuals. In Canada, for instance, while corporations pay dividends with after-tax income, individuals receive a tax credit related to dividend income. Under the 2005 enhanced dividend tax credit, individuals receive a non-refundable tax credit of more than one-fourth of the dividend value. Depending on an individual's marginal tax rate, the dividend tax credit can result in effective tax rates on dividends as low as 3 percent, but up to 30 percent. In the U.S., most dividends are taxed at a maximum rate of 15 percent for individuals (referred to below as the "dividend tax cut") effective with the passage of the Jobs and Growth Tax Relief Reconciliation Act of 2003. This favorable rate is currently set to expire after 2010, if not renewed.

  It is important to note that the tax advantages related to dividends may be diminished or not available to international investors. Cross-border taxation of dividends also differs depending on the direction of the investment (*i.e.*, a U.S. investment in a Canadian security, a Canadian investment in a U.K. security, etc.), as well as the type of account in which the investment is held (*i.e.*, retirement versus taxable).[30] Similarly, institutional investors tend to constitute a large portion of utility

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[30] For a description of cross-border taxation of dividends, *see*, Susan E.K. Christoffersen, et al., "Crossborder dividend taxation and the preferences of taxable and nontaxable investors: Evidence from Canada," *Journal of Financial Economics*, August 24, 2004.

stock ownership of U.S. utilities. Since many of those institutions are tax-exempt investors, it is not clear that the dividend tax cut beneficially affected all utility investors. Moreover, many U.S. investors hold utility stocks in tax-advantaged 401-k accounts; here again, the effect of the dividend tax cut on current income is not definitive.

Thus, the true effect of dividend taxation, if any, requires knowledge of the individual investor's tax position. In and of itself, it is not evident that the dividend tax rules in one country versus another would lead to differences in ROE on a comparative basis.

- *Other Macroeconomic Factors*: Table 10 provides data for Canada and the U.S. regarding indicators of economic growth and stability, as well as market returns.

TABLE 10: MACROECONOMIC FACTORS[31]

	GDP Growth		Return on:		CPI		Exchange Rate
	Canada	U.S.	S&P/TSX (TSE 300)	S&P 500	Canada	U.S.	
1981	3.05	2.50	(0.14)	(0.10)	12.40	10.32	0.83
1982	(2.94)	(1.90)	0.02	0.15	10.90	6.16	0.81
1983	2.75	4.50	0.29	0.17	5.80	3.21	0.81
1984	5.67	7.20	(0.06)	0.01	4.30	4.32	0.77
1985	5.40	4.10	0.21	0.26	4.00	3.56	0.73
1986	2.64	3.50	0.06	0.15	4.10	1.86	0.72
1987	4.10	3.40	0.03	0.02	4.40	3.65	0.75
1988	4.86	4.10	0.07	0.12	4.00	4.14	0.81
1989	2.54	3.50	0.17	0.27	5.00	4.82	0.85
1990	0.27	1.90	(0.18)	(0.07)	4.80	5.40	0.86
1991	(1.87)	(0.20)	0.08	0.26	5.60	4.21	0.87
1992	0.91	3.30	(0.05)	0.04	1.50	3.01	0.83
1993	2.30	2.70	0.29	0.07	1.80	2.99	0.78
1994	4.73	4.00	(0.02)	(0.02)	0.20	2.56	0.73
1995	2.77	2.50	0.12	0.34	2.20	2.83	0.73
1996	1.54	3.70	0.26	0.20	1.60	2.95	0.73
1997	4.37	4.50	0.13	0.31	1.60	2.29	0.72
1998	3.31	4.20	(0.03)	0.27	0.90	1.56	0.67
1999	4.54	4.50	0.30	0.20	1.70	2.21	0.67
2000	4.68	3.70	0.03	(0.10)	2.70	3.36	0.67
2001	1.50	0.80	(0.14)	(0.13)	2.60	2.85	0.65
2002	3.90	1.60	(0.14)	(0.23)	2.20	1.58	0.64
2003	2.60	2.50	0.24	0.26	2.80	2.28	0.72
2004	2.50	3.90	0.12	0.09	1.90	2.66	0.77
2005	3.10	3.20	0.22	0.03	2.20	3.39	0.83
2006	1.90	3.30	0.15	0.14	2.00	3.23	0.88
25 Year Ave.	2.74	3.12	0.08	0.11	3.58	3.52	
10 Year Ave.	3.24	3.22	0.09	0.08	2.06	2.54	
5 Year Ave.	2.80	2.90	0.12	0.06	2.22	2.63	
		Standard Deviation	0.145	0.152			
Correlation	0.81		0.65		0.87		

As can be seen in Table 10, the correlation between GDP growth in the two countries is quite high, as is the correlation between the consumer price indices for each country, indicating that these metrics tend to vary together over time between the two countries. For returns on broad market indices (*i.e.*, the Toronto Stock Exchange/S&P and the S&P 500), the correlation is not as robust; however, there still is a strong positive correlation. In addition, the returns on these two indices show a similar volatility as measured by their standard deviations. Based on these macroeconomic factors, there are no obvious

[31] Sources: Canada GDP, Exchange Rate, and CPI – Statistics Canada as of April 17, 2007; U.S. GDP – U.S. Bureau of Economic Analysis as of March 29, 2007; S&P 500 returns – Yahoo! Finance; S&P/TSX (TSE 300) –Yahoo! Finance (2000-2007), finance.sauder.ubc.ca/courses/comm472/TSE300.xls (pre-2000); U.S. CPI – U.S. Bureau of Labor Statistics.

dissimilarities between Canada and the U.S. (*i.e.*, in terms of volatility in growth, inflation, or exchange rates) which could explain significant differences in investors' expectations. Based on the past five years, investors in the Toronto exchange stocks have enjoyed a six percent greater return than those investing in the U.S. S&P 500. Over the long term, however, returns in the respective markets have been more similar. Furthermore, the magnitude and significance of trade between the two countries would indicate the integration of the two markets. In 2006, Canada exported 81.6 percent of its total exports to the U.S. and imported from the U.S. 54.9 percent of its total imports.[32]

32 Strategis, Industry Canada, February 2007.

V. COMPETITION FOR CAPITAL IN CANADA VERSUS THE U.S.

A company's access to capital is a key consideration in setting a fair return. Without access to capital (at reasonable cost rates), a utility would be challenged to maintain its basic systems, and ultimately system integrity would be jeopardized, let alone any future capital expansion plans. Companies obtain capital in a variety of ways, through debt or equity issuances, or in the form of equity infusions from their parent. Regardless of where capital is coming from, there is a cost for providing that capital that compensates either the creditor, the investor, or the parent for the risk they take on in providing capital to the entity, and that compensation should be no less than what could be received by an alternative investment target of comparable risk.

This section of the report examines whether capital for utility investment between the Canadian and U.S. markets is integrated, and whether Canadian companies must compete with U.S. companies for capital. To answer this question, consideration has been given to three primary questions: (1) Are there fundamental differences between the securities markets of the U.S. and Canada that would result in corresponding differences in the countries' required returns? (2) Do the investment bases in U.S. and Canadian gas utilities suggest that the markets are integrated? (3) Is capital migrating to jurisdictions with the higher returns? In the following section, those questions will be analyzed and discussed.

<u>International Market Return on Equity – Canada vs. U.S.</u>

Morningstar, Inc. (formerly Ibbotson Associates) identifies several methods for determining the international cost of capital, highlighting differences between countries. Of those methodologies described by Morningstar, four are employed below to ascertain if there are fundamental differences in the required returns between Canada and the U.S. that are attributable to the countries' equity markets themselves. Such differences would address inflation, political risk, exchange rate risk, and other macroeconomic factors.

The first methodology employed is the "International CAPM". Morningstar states that the principles of the CAPM can also be applied to the international market. The definition of the market portfolio can be expanded to include the equity markets of all countries of the world. Morningstar's International CAPM model uses the country specific risk free rate and Beta, and uses an equity risk premium calculated on a world wide basis.[33] Beta is estimated using the world equity market as the benchmark. Morningstar determined the world equity risk premium to be 7.73 percent, and the Betas for the U.S. and Canada are determined to be 0.99 and 0.96, respectively.[34] Using both countries current respective long term government bonds for the risk free rate results in an ROE for the U.S. of 12.45 percent and for Canada, 11.62 percent, 83 basis points below the U.S.[35]:

U.S. CAPM = 4.80 + 0.99 (7.73) = 12.45%

Canada CAPM = 4.20 + .96 (7.73) = 11.62%

A second approach to estimating the required return in international markets, put forward by Morningstar, is the "Country Risk Rating Model", which takes into account a forward-looking measure of risk for alternative markets. This approach uses a linear regression model on a sample of returns as the dependent variable and the natural log of country credit ratings as the independent variable. This analysis indicates that the U.S. required equity return should be 16 basis points lower than that of the Canadian return, based upon the relationship of the relative country credit rating and historical returns:

U.S. credit rating = 94.5, U.S. required equity return = 10.60%[36]

Canada credit rating = 93.7, Canadian required equity return = 10.76%[37]

A third approach to estimating the international required return on equity, according to Morningstar, uses a spread methodology, between countries. This approach adds a country specific spread to a cost of equity determined from more conventional means. The spread between long term government bonds is added or subtracted to the U.S. cost of equity estimate obtained through a normal CAPM assuming a market Beta of 1.00. This approach results in a 60 basis point spread, where the U.S. long term government bond is 60 basis points above its Canadian counterpart:

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33 Morningstar relied upon the Morgan Stanley Capital International (MSCI) world index as a proxy for world markets, *see* SBBI Morningstar 2007 Yearbook, Valuation Edition, at p. 178.

34 SBBI Morningstar 2007 Yearbook, Valuation Edition, at p. 179.

35 Taking the average monthly bond yield for the preceding 12 months, results in increases in the U.S. and Canada risk free rates of 5 basis points and 4 basis points, respectively, resulting in a negligible impact on the ROE. Hence, for purposes of this analysis, current spot yields are reasonably representative of 12 month averages.

36 SBBI Morningstar 2007 Yearbook, Valuation Edition, at p. 181.

37 Ibid.

U.S. Required Equity Return = 4.80 + 1 (7.13) = 11.93%

Spread = U.S. 30-Year Treasuries – Canada Long Bond = 4.80% - 4.20% = 0.60%

Canadian Equity Return = 11.93% - .60% = 11.33%

The last of the methodologies proposed by Morningstar is a "Relative Standard Deviation Model". In this model, the standard deviation of international markets is indexed to the standard deviation of the U.S. market. Countries with higher standard deviations than the U.S. are given a higher equity risk premium in proportion to their relative standard deviation. Morningstar's study indicates that the Canadian standard deviation relative to the U.S. market is 1.25[38], hence Canada's risk premium should be the product of the U.S. risk premium and the Canada/U.S. index, or 7.13 x 1.25 = 8.91. This increased risk premium would yield a higher Canadian return than that in the U.S. by 117 basis points (13.11 percent - 11.94 percent), derived below:

U.S. Required Equity Return = 4.80 + 1 (7.13) = 11.93%

Canadian Required Equity Return = 4.20 + 1(8.91) = 13.11%

The four Morningstar approaches identified above are summarized in the Table 11:

TABLE 11: INTERNATIONAL COST OF CAPITAL SUMMARY

Morningstar Methodology	U.S. Return	Canadian Return	Difference
International CAPM	12.45%	11.62%	0.83%
Country Risk Rating Model	10.60%	10.76%	(0.16%)
Country-Spread Model	11.93%	11.33%	0.60%
Relative Standard Deviation Model	11.93%	13.11%	(1.18%)
Average – Arithmetic	11.73%	11.71%	0.02%
Average – Geometric	11.71%	11.67%	0.04%

As Table 11 indicates, the four international cost of capital methodologies yield diverse results depending on the drivers of the methodology employed (*i.e.*, bond yields or relative risk metrics), with results ranging from a Canadian required return exceeding the U.S. required return by 118 basis points, to a U.S. required return exceeding the Canadian

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38 Ibid., at p. 183.

required return by 83 basis points. However, the arithmetic and geometric average of all approaches indicate nearly identical results for both the Canadian and the U.S. required returns, with the average difference of all methods being between two and four basis points. These results imply that the impact of the currently lower Canadian bond yield is offset by the increased relative risk of Canadian returns (as determined under these methodologies).[39] As a result, there do not appear to be determinative market differences between the U.S. equities market and the Canadian equities market at this time to justify any sustained differences in required returns on equity.

In a 2002 study performed by Dimson, Marsh and Staunton, the authors indicate that when deriving a forward looking projection of required return on equity from a purely historical estimate of the risk premium, it is necessary to "reverse-engineer" the facts that impacted stock returns over the past 102 years, backing out factors that could not be anticipated to be recurring in the future, such as unanticipated growth or diminished business risk through technological advances. To this point, the authors state:

> While there are obviously differences in risk between markets, this is unlikely to account for cross-sectional differences in historical premia. Indeed much of the cross-country variation in historical equity premia is attributable to country-specific historical events that will not recur. When making future projections, there is a strong case, particularly given the increasingly international nature of capital markets, for taking a global rather than a country by country approach to determining the prospective equity risk premium…
>
> ...Indeed it is difficult to infer expected premia from any analysis of historical excess returns. It may be better to use a "normal" equity premium most of the time, and to deviate from this prediction only when there are compelling economic reasons to suppose expected premia are unusually high or low.[40]

The current disparity between Canadian and U.S. long term bond yields is informative at least in part in understanding the recent differences in authorized ROE's in the U.S. and

39 According to the Country Risk Rating Model and the Relative Standard Deviation Model Canadian returns should be higher than those of the U.S. Consideration of the lower Canadian bond yield in the International CAPM Model and the Country-Spread Model, indicates that Canadian returns should be lower than U.S. returns. As such, it appears that the higher risk of Canadian returns as evidenced by the credit rating and standard deviation of Canadian returns, is mitigated by the lower bond yield relative to that of the U.S.

40 Elroy Dimson, Paul Marsh and Mike Staunton, Global Evidence on the Equity Risk Premium, Copyright September 2002.

Canada. Historically, however, as discussed below, these bond yields have been highly correlated, and based on historical performance, the current spread may not be sustainable.

Bond Yields

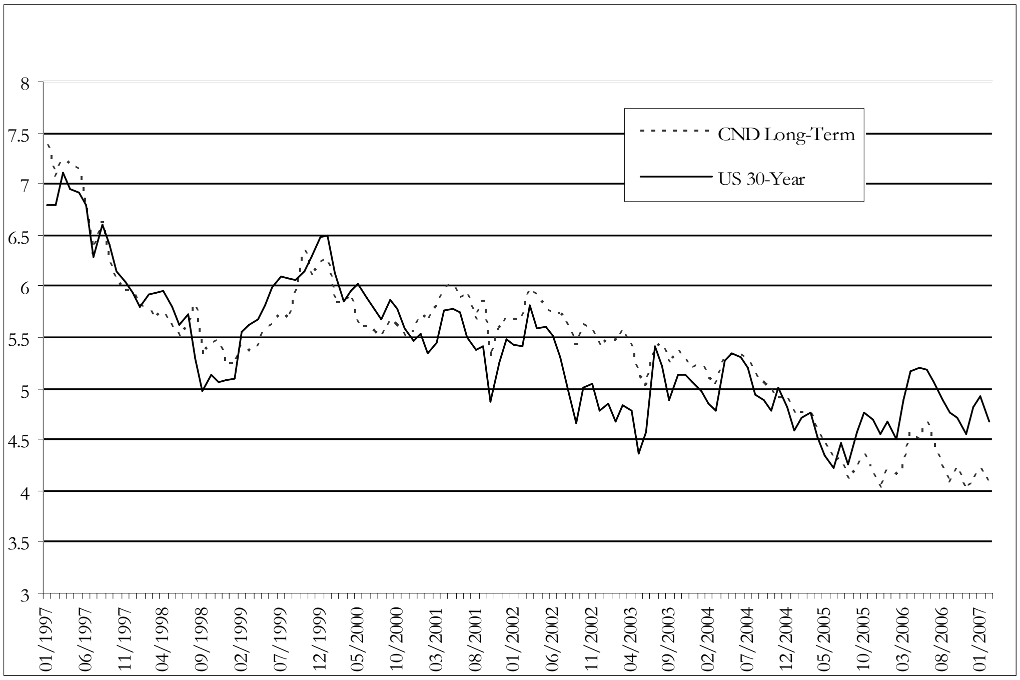
The correlation between the Canadian and U.S. Treasury bonds was noted by the NEB in its decision establishing an ROE formula for NEB-regulated pipelines. "[T]he Board is of the view that inflationary expectations in the U.S. are likely to put upward pressure on U.S. interest rates. This, in turn, is likely to exert upward pressure on Canadian interest rates."[41]

While the spread between Canadian and U.S. long-term bond yields has averaged three and two basis points over the past five and ten-year periods, respectively (with Canadian bond yields exceeding U.S. yields, on average), Canadian bond yields have decreased relative to U.S. bond yields over the past year. In addition, the forecast ten-year bond rate is 4.15 percent in Canada, as compared to the 4.85 percent forecast for the U.S. ten-year Note.[42] Inasmuch as this spread is expected to continue, it accounts for some of the current difference in ROEs between Canada and U.S. However, as the two yields have historically been very highly correlated, with a minimal spread between them, the difference in yields may not persist over the long run.

41 National Energy Board, Reasons for Decisions, RH-2-94, March 1995, at p. 6.

42 The ROE formula in Ontario uses the average of the three and 12 month forward ten-year Canadian bond forecasts, plus the historical spread between the ten and the 30-year bonds. For an approximation of the ten-year U.S. Note forecast of 4.85 percent, CEA used an average of the three and 12 month forward ten-year Treasury Note as supplied by Blue Chip Economic Indicators, October 10, 2006.

CHART 10: COMPARISON OF YIELDS ON THE CANADIAN LONG-TERM BOND VS. THE U.S. 30-YEAR BOND



<u>Investor Base of Canadian Gas Utilities</u>

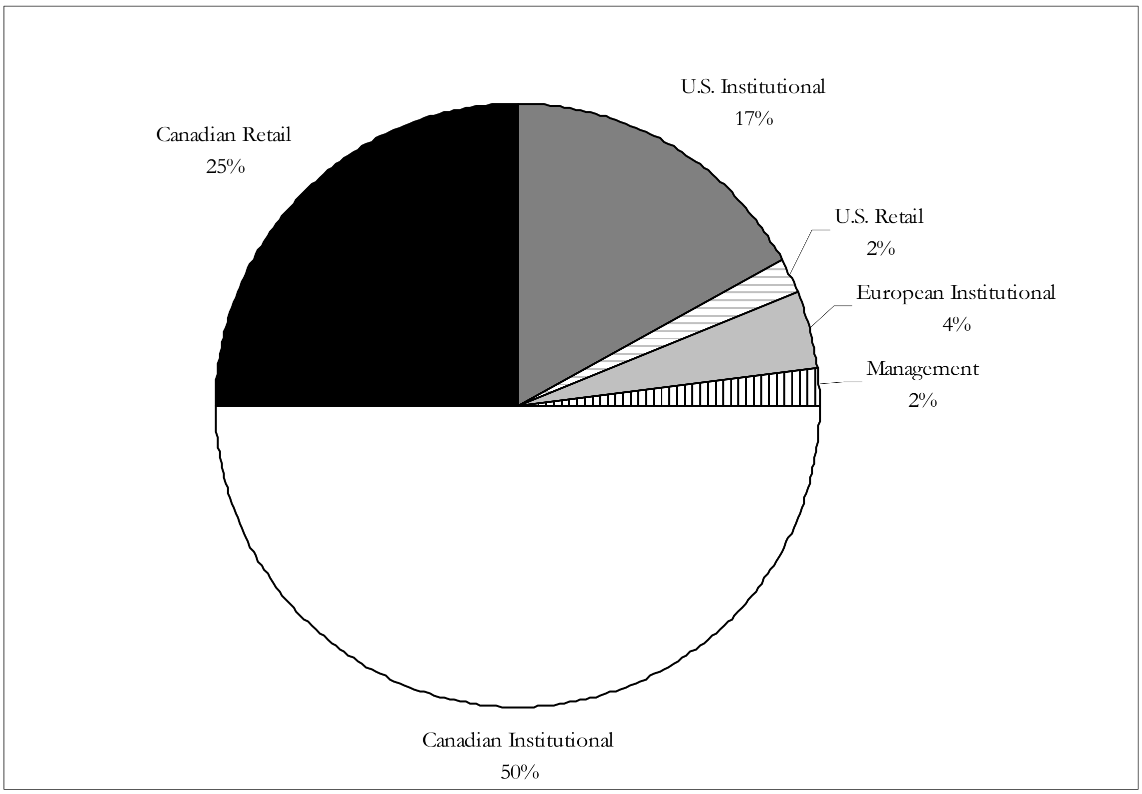
CEA has found evidence that there is a high degree of integration of the capital markets between the U.S. and Canada, though there appears to be evidence of a "home country" bias for investors, in that investors tend to seek investments in their home countries before investing abroad, using foreign holdings as a means of balancing portfolios. This may be due in part to preferential tax treatment encouraging local investment or reluctance on the part of the investor to invest in unfamiliar territory. Nonetheless, there is substantial institutional investment flowing across borders.

For example, according to a December 2003 CGA study, the average pension fund in Canada was invested 56 percent in equities and 44 percent in debt and other instruments, or roughly 60 percent equity and 40 percent debt. The assumed asset allocation was 35 percent Canadian equities, 12.5 percent U.S. equities, 12.5 percent International equities, and 40 percent bonds.[43] Similarly, the capitalization of Enbridge further illustrates the bias towards

43 Andrews, Doug, An Examination of the Equity Risk Premium Assumed by Canadian Pension Plan Sponsors, July 2004, at p. 4.

investing in local companies, as indicated by a breakdown of the investor base in Enbridge Inc. As can be seen in Chart 11, 75 percent of Enbridge Inc.'s equity investors are Canadian. However, the U.S. share of investment is still significant at 19 percent of Enbridge's investor base. It is worthy to note that U.S. investors do play a significant role in the capitalization of Canadian companies. Even though the U.S. share is a minority, one could argue that in order to attract this incremental capital, Canadian companies are competing on the margin for the same capital as U.S. gas utilities.

CHART 11: ENBRIDGE INC. INVESTOR BASE[44]



Migration of Capital across U.S. and Canadian Border

The question remains, if the current differences between the Canadian and the U.S. equities markets are completely offsetting, and there is significant integration between U.S. and Canadian markets, how is it that Ontario utilities are not required to meet U.S. higher returns to attract capital in Ontario? Through interviews with key market participants and representatives of customer groups, and other individuals with past involvement in ROE

44 Source: Enbridge Inc.

proceedings, as well as analysis of the factors discussed above, there appear to be four primary reasons why capital is retained in Canada: (1) the home country bias; (2) Canadians perceive the U.S. regulatory environment to be more unpredictable than the Canadian regulatory environment; (3) most Canadian investor owned utilities are part of a greater holding company structure, where the parent has an obligation to maintain system integrity; and (4) market participants recognize the reciprocity of the ROE adjustment mechanism, and believe that returns are currently at the bottom.

On the issue of home country biases, some of the individuals among those surveyed for this study indicated that the average Canadian retail investor would not invest across the border to the U.S., despite the fact that returns might be higher. This may be due in part to tax incentives that are lost when investing in a foreign company. Further, pension funds have various internal restrictions that limit investment in foreign nations, to keep jobs and income in Canada. As such, large investors such as pension funds and mutual funds have prescribed investment levels in foreign markets.

To the second point of relative risk between the Canadian and the U.S. regulatory environments, certain of the individuals who were interviewed as part of this study alluded to the greater unpredictability of the U.S. regulatory environment versus that of Canada. The California energy crisis and changing and evolving regulatory structures in the U.S. were mentioned in discussions of relative risk of the U.S. versus the Canadian utility markets. It seems that despite the lower ROEs, the Canadian regulators are perceived by investors and analysts as being highly supportive. Some participants offered that even though current ROEs in Ontario were low, the protection afforded by the OEB to enable the utility to actually earn the authorized return was much more certain than in the U.S. Nothing was identified in this analysis to justify a differential between U.S. and Canadian returns on the basis of relative risk. Nonetheless, Canadian investors apparently perceive greater risk in investing in a U.S. utility versus that of a Canadian utility, and prefer to hold investments in their home country, where they believe returns are currently low but are not subject to the same risks of non-recovery as those of U.S. returns.

With respect to the third point, the natural gas distribution sector in Ontario and throughout much of Canada is comprised of several gas utilities that are part of a larger holding company structure. Though utilities that are part of a holding company structure may issue debt at the utility level, the flow of equity capital to these utilities typically comes from the parent in the way of equity infusions. While it is true that companies in a holding company structure compete for capital in much the same way as stand alone companies, an equity holder in a stand alone company can sell that investment, whereas there is little risk that utilities in a holding company structure would not be provided adequate capital by the parent to sustain their operations.

As many market participants stated during the survey phase of this study, a company makes a strategic commitment when deciding to invest in gas distribution in Canada. Most of the holding companies with Canadian utilities have diverse energy portfolios with a blend of returns. Even in an environment of lower allowed returns, key market participants indicated that they would either stay the course and provide all the capital necessary to provide a safe and efficient gas distribution system, or they would make a case to the regulatory authorities for regulatory relief. Few market participants indicated that they would divert capital to higher return jurisdictions, in order to minimize the effect of low returns. None indicated that they had considered abandoning utility operations in Canada due to the current return environment. As one key market participant stated, "you are either in the game or you are not". Thus, the regulator is largely in the driver's seat in this relationship, relying on principals of a fair return in setting allowed returns.

With respect to the final point, market participants recognize the symmetrical nature of the OEB adjustment mechanism and believe that interest rates are at historical lows and eventually will rebound. As demonstrated earlier in this report, the ROE adjustment mechanism may in fact be approaching its lowest point and its greatest disparity from U.S. returns. While CEA did not perform an analysis of the effect of allowed returns on the financial integrity of regulated utilities or on customers' rates, we do note that, all else being equal, at extremely low interest rates and correspondingly low returns, unexpected earnings variations (*i.e.*, deviations from those conditions that would have been anticipated when setting rates) will generally have a more pronounced effect on the financial condition of the utilities, as those deviations would be applied to a smaller earnings base. Accordingly, in an extreme low (or high) interest rate environment (*i.e.*, at those points in which the ROEs in Canada and the U.S. would most greatly diverge), further consideration is warranted to assess whether the allowed return is consistent with the established standards.

VI. Competition for Capital for Stand-Alone Companies Versus Subsidiaries

In general, subsidiaries of larger corporations compete for capital in much the same way that stand-alone entities would. Specifically, investment decisions at the parent level involve seeking a certain amount of return for a given amount of risk, much the same as investment decisions are made by investors when buying stakes in stand-alone companies or purchasing assets. Inasmuch as one subsidiary can provide a better return to the parent than another subsidiary of comparable risk, it is reasonable to assume the parent would prefer to invest in the more profitable company, all else being equal.

One important distinction, however, between stand-alone and subsidiary investments is the difference in relative liquidity of the investments. A parent company may have to accept lower returns from a subsidiary than it would demand from "outside", or third party, investments, especially if the parent has no easy, cost-effective method for exiting the business. In the words of one industry participant, a parent company is not going to let a subsidiary "flounder" because it offers substandard returns. In some ways, this effect is compounded for a utility company, in that it must maintain safe, dependable operations. However, a parent company would most likely seek to minimize additional capital investment in its underperforming subsidiary if a more attractive return were available elsewhere.

Additionally, affiliated companies can generate certain types of tax savings that stand-alone entities cannot. These tax savings can materialize in the form of one affiliated company being able to offset its taxable income with a loss from the operations of another affiliate. It is important to realize, however, that these tax savings do not affect the relative risk of the individual affiliated companies, and there is much debate as to the degree that these savings can and should affect the cost of capital at the subsidiary level.[45]

To test whether a "stand-alone" premium exists within the companies studied as part of this report, CEA segregated the Canadian and U.S. companies into stand-alone and subsidiary

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45 Please note that CEA is not offering an opinion regarding the issue of consolidated taxes as it pertains to utility rate-making in this report.

groupings. As stated previously, there are a multitude of jurisdictional and company-specific business, operating, financial, and regulatory risks that must be taken into consideration when evaluating individual utility ROEs and estimating the equity returns expected by investors. However, because the data set used comprises the entire population of recently set ROEs for gas distribution companies in Canada and the U.S., CEA used this as a starting point to determine if any discernible trend exists. A summary of these results is presented in Table 12.

TABLE 12: ROES FOR STAND-ALONE VERSUS SUBSIDIARY COMPANIES

Utility Group	Stand-Alone	Subsidiary
Canada	8.94% (average for PNG companies)	8.62% (7 subsidiaries)
U.S.	9.86% (6 companies)	10.46% (28 subsidiaries)

As shown, the lone stand-alone company in Canada, Pacific Northern Gas ("PNG"), has, on average for its operating divisions, a higher allowed ROE than the remainder of the Canadian utilities, all of which are subsidiaries of larger corporations.[46] It should be noted, however, that PNG, with its three gas distribution companies, is known as being generally riskier than other Canadian utilities, due to its relative small size and reliance on large customers.

Conversely, in the U.S., over the last two years, stand-alone companies have, on average, been awarded lower ROEs than subsidiary companies. The spread between the mean ROEs of these two groups is 60 basis points. These conflicting results demonstrate two things: (1) that while corporate structure may influence ROE, its effect is not consistent within this group of companies; and (2) there are many other factors with greater effects on ROE. This result is consistent with the "independent firm approach" to ratemaking, whereby the subsidiary is treated as if it was an independent firm and requires the subsidiary to earn its stand-alone cost of equity. Required rates of return are thus considered a function of the risk of the asset, regardless of stock ownership.

[46] PNG is comprised of three divisions each with separate ROEs. However, as PNG has no other active operations, the company is considered "stand-alone" for purposes of this analysis.

VII. CONCLUSIONS AND SUMMARY OF FINDINGS

Based on the foregoing analyses, CEA's general conclusions are as follows:

(1) The average ROEs for Enbridge and Union (8.82 percent for 2006 and 8.47 percent for 2007) are approximately 150 to 185 basis points (1.50 percent to 1.85 percent) lower than average allowed U.S. ROEs for gas distribution utilities. When certain U.S. companies that are less comparable to the Ontario utilities are excluded from the comparison, the gap between Canadian and U.S. ROEs remains relatively constant, at between approximately 160 and 200 basis points.

(2) While the ranges of ROEs in Canada and the U.S. do not overlap, allowed returns in the U.S. are dispersed over a wider spectrum than in Canada, from 9.45 percent to 11.20 percent in the U.S. (*i.e.*, 175 basis points) versus from 8.37 percent to 9.07 percent in Canada (*i.e.*, 70 basis points). The range of ROEs for the narrower group of more comparable U.S. utilities is from 9.50 percent to 11.20 percent (*i.e.*, 170 basis points), roughly equivalent to that of the larger U.S. group.

(3) Enbridge and Union also have lower allowed equity ratios than U.S. companies, on average. Enbridge and Union's allowed equity percentages are currently 35.00 percent and 36.00 percent, as compared to 46.00 percent on average for the eight comparable U.S. companies (48.00 percent for the entire U.S. group). In general, financial theory would suggest that as equity ratios decrease, the cost of equity increases.

(4) The OEB's formulaic adjustment factor of .75 is reasonably reflective of the historical (*i.e.*, pre-1997) relationship between Canadian authorized returns and long term government bond yields. It also is significantly more sensitive to changes in interest rates than is suggested by regression results based on U.S. data. The difference in the interest rate sensitivity of each, the U.S. regression model and the Ontario adjustment mechanism, at least partially explains the recent disparity between U.S. authorized returns and Ontario authorized returns. The OEB ROE adjustment mechanism, however, is

reciprocal; as interest rates recover ROEs will rise at a faster rate in Ontario than in the U.S. Ontario authorized returns could eventually surpass U.S. authorized returns, if interest rates rise above the point at which they were when the mechanism was established in 1997.

(5) Through our research, CEA has identified a strong positive historical relationship between long term Canadian Bond yields and Canadian authorized returns. The ROE adjustment formula employed by the OEB appropriately characterizes that historical relationship. While CEA did not perform an analysis of the effect of allowed returns on the financial integrity of regulated utilities or on customers' rates, we do note that, all else being equal, at extremely low interest rates and correspondingly low returns, unexpected earnings variations (*i.e.*, deviations from those conditions that would have been anticipated when setting rates) will generally have a more pronounced effect on the financial condition of the utilities, as those deviations would be applied to a smaller earnings base. Accordingly, in an extreme low (or high) interest rate environment (*i.e.*, at those points in which the ROEs in Canada and the U.S. would most greatly diverge), further consideration is warranted to assess whether the allowed return is consistent with the established standards. This may require the consideration of additional qualitative and financial metrics in making the ROE determination.

(6) On the whole, there are no evident fundamental differences in the business and operating risks facing Ontario utilities as compared to those facing U.S. companies or other provinces' utilities that would explain the difference in ROEs.

(7) Other market related distinctions and resulting financial risk differences, particularly between Canada and the U.S., do exist. These factors, including differences in market structure, investor bases, regulatory environments, and other economic factors may have an impact on investors' return requirements for Canadian versus U.S. utility investments. However, through analysis and interviews with key market participants, representatives of customer groups, and other individuals with past involvement in ROE

proceedings in Canada and the U.S., these differences are determined to be negligible.

(8) While the gas markets in the U.K., the Netherlands, and Australia bear certain resemblances to those of Canada and the U.S., there are a few substantial differences that weaken the comparison. Thus, allowed returns in these countries are not considered adequate benchmarks against which to examine ROEs in Ontario.

(9) As a result of the interplay between the Canadian and U.S. markets, Canadian utilities compete for capital essentially on the same basis as utilities in the U.S.

(10) CEA concludes that stand-alone companies compete for capital just as subsidiaries of larger holding companies do, as the latter must compete among their affiliates for parental investment. Nonetheless, the parental obligation to invest necessary capital to maintain system integrity will typically provide the wholly owned subsidiary sufficient capital to sustain operations, where no such provision exists for stand alone utilities as external investors have no similar obligation to invest. Thus, one could argue that subsidiaries enjoy the benefit of more patient capital, but over time, the equity returns must ultimately reward the parent for investments of comparable risk.

VIII. List of Appendices

Appendix A – Listing of market participants interviewed

Appendix B – Listing of data sources and documents considered

Appendix C – Discussion of significant ROE-related decisions in Canada and the U.S.

IX. List of Exhibits

Exhibit 1 – "ROE Database" of Canadian and U.S. gas distribution companies

Exhibit 2 – Complete listing of U.S. gas distribution ROE awards, 2005 to present

APPENDIX A
LISTING OF INDIVIDUALS INTERVIEWED

As part of the research phase of this report, CEA interviewed many market participants, consumer group representatives, and other individuals with past or current involvement in ROE proceedings in Ontario and other jurisdictions. In addition, while not listed here, we would also like to thank the many individuals at the OEB, other regulatory boards, and companies who provided us documentation and other information during the process.

- Professor Laurence Booth, CIT Chair in Structured Finance, Rotman School of Management, University of Toronto
- Brad Boyle, Treasurer, Enbridge Gas Distribution Inc.
- R. J. Campbell, Manager, Regulatory Policy & Research, Enbridge Gas Distribution Inc.
- Bryan Gormley, Director, Policy & Economics, Canadian Gas Association
- Mike Packer, Director, Regulatory Affairs, Union Gas Limited
- Jay Shepherd, Counsel to the School Energy Coalition, Shibley Righton LLP
- Karen J. Taylor, Managing Director, Pipelines & Utilities Equity Research, BMO Capital Markets
- Peter Thompson Q.C., Counsel for the Industrial Gas Users Association, Borden, Ladner, Gervais LLP.
- An additional market participant who requested to remain anonymous.

APPENDIX B
LISTING OF DATA SOURCES AND DOCUMENTS CONSIDERED

Canada

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APPENDIX C
DISCUSSION OF SIGNIFICANT ROE-RELATED DECISIONS IN CANADA AND THE U.S.

The United States Supreme Court's precedent-setting *Hope* and *Bluefield* decisions established the standards for determining the fairness and reasonableness of a utility's allowed return on common equity. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; and (2) adequacy of the return to support credit quality and access to capital.

The *Hope* and *Bluefield* cases read, in pertinent part:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[47]
>
> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory…[48]
>
> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[49]

The Supreme Court of Canada in *Northwestern Utilities vs. City of Edmonton* established a similar definition of fair return. As stated by Mr. Justice Lamont in that case:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the

47 Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 1923, at 692-693 ("Bluefield").

48 Id., at 690-692.

49 Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 1944, at 603 ("Hope").

> capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise…[50]

The standards set out in these court cases are endorsed and used by the Federal Court of Canada and the NEB.[51] In its December 1971 Decision, the NEB concluded as follows in respect of the framework for consideration of an appropriate rate of return for TransCanada:

> The Board is of the opinion that in respect of rate regulation, its powers and responsibilities include on the one hand a responsibility to prevent exploitation of monopolistic opportunity to charge excessive prices, and equally include on the other hand the responsibility so to conduct the regulatory function that the regulated enterprise has the opportunity to recover its reasonable expenses, and to earn a reasonable return on capital usefully employed in providing utility service. Further, it holds that to be reasonable such return should be comparable with the return available from the application of the capital to other enterprises of like risk. The Board accepts that, with qualifications, the rate of return is the concept perhaps most commonly used to project for some future period the ratio of return which has been found appropriate for the capital employed usefully by a regulated enterprise in providing utility service in a defined test period. The expectation is that, pending major changes, that ratio will provide a return, notwithstanding changes in the amount of capital invested, which will be fair both from the viewpoint of the customers and from the viewpoint of present and prospective investors.

An example of how the NEB describes their utilization of the fair return standard is seen in the RH-2-2004 (Phase II) proceeding.[52]

> The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and

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[50] Northwestern Utilities v. City of Edmonton [1929] S.C.R. 186 (NUL 1929)

[51] *See* TransCanada PipeLines Limited v. Canada (National Energy Board), [2004] F.C.A. 149, paragraphs 35 and 36; AO-1-RH-1-70 Reasons for Decision, pp. 6-6 through 6-9; RH-4-2001 Decision, pages 10-12.

[52] Reasons for Decision, TransCanada PipeLines Limited, RH-2-2004, Phase II, April 2005, Cost of Capital.

- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).[53]

Capital Structure:

The U.S. Supreme Court and various utility commissions have long recognized the role of capital structure in the development of a just and reasonable rate of return for a regulated utility. In particular, a utility's leverage, or debt ratio, has been explicitly recognized as an important element in determining a just and reasonable rate of return:

> Although the determination of whether bonds or stocks should be issued is for management, the matter of debt ratio is not exclusively within its province. Debt ratios substantially affect the manner and cost of obtaining new capital. It is therefore an important factor in the rate of return and must necessarily come within the authority of the body charged by law with the duty of fixing a just and reasonable rate of return.[54]

The NEB, in the RH-2-94 Multi-Pipeline Cost of Capital Decision, established the ROE for a benchmark pipeline to be applied to all pipelines in that hearing. It then determined that any risk differentials between the pipelines could be accounted for by adjusting the common equity ratio.[55]

The NEB stated that, "case law establishes that it is the overall return on capital to the company which ought to meet the comparable investment, financial integrity and capital attraction requirements of the fair return standard." Yet they indicated that this does not in the NEB's view, "require that the Board make the necessary determinations solely by means of examining evidence on overall return."[56]

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53 Id., at p. 17.

54 New England Telephone & Telegraph Co. v. State, 98 N.H. 211, 220, 97 A.2d 213, 1953, at 220-221 citing New England Tel. & Tel. Co. v. Department of Pub. Util., (Mass.) 327 Mass. 81, 97 N.E. 2d 509, 514; Petitions of New England Tel. & Tel. Co. 116 Vt. 480, A.2d 671 and Chesapeake & Potomac Tel. Co. v. Public Service Comm'n, (Md.) 201 Md. 170, 93 A..2d 249, 257.

55 RH-2-94, at p.25.

56 Reasons for Decision, TransCanada PipeLines Limited, RH-2-2004, Phase II, April 2005, Cost of Capital, at p. 19.

					Parent Company							Customer Mix [1]								
Company	Jurisdiction	Most Recent ROE	Date	Allowed Equity %	Percent Regulated Revenue	Percent Regulated Net Income	Percent Gas Distribution Revenue	Book Value (million $CAD)	Total Revenue (million $CAD)	Gas Distribution Revenue (million $CAD)	Total Gas Distribution Customers	Ind.	Comm.	Res.	Whlsl & Other	Trans- portation	Gas Volume Sold $(10^9 m^3)$	Credit Rating (DBRS/ S&P)	Interest Cov. Ratio [2]	Un- bundled
CANADIAN COMPANIES																				
Enbridge Gas Distribution [3]	Ontario, CAN	8.39%	2007	35.00%	100%	100%	98%	$4,779	$3,016	$2,958	1,819,765	5%	23%	47%	2%	23%	11.55	A/A-	1.84	Y
Union Gas	Ontario, CAN	8.54%	2007	36.00%	100%	100%	91%	$3,442	$2,079	$2,046	1,268,000	12%	20%	7%	0%	61%	13.21	A/BBB+	1.91	Y
PNG, Ltd. (PNG West Division)	BC, CAN	9.02%	2007	40.00%	100%	100%	89%	$157	$139	$124	39,511	10%	22%	25%	0%	43%	0.33	BBB/BBB	2.47	Y
PNG, Ltd. (PNG Tumbler Ridge)	BC, CAN	9.02%	2007	36.00%	100%	100%	89%	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	BBB/BBB	[4]	Y
PNG, Ltd. (PNG Ft. St. John/Dawson Creek/FortisBC)	BC, CAN	8.77%	2007	36.00%	100%	100%	89%	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	[4]	BBB/BBB	[4]	Y
Terasen Gas Inc. (BCGU)	BC, CAN	8.37%	2007	35.00%	98%	100%	86%	$2,468	$1,525	$1,525	815,000	2%	18%	31%	0%	48%	5.72	A/A	2.06	Y
Terasen Gas (Vancouver Island) Inc.	BC, CAN	9.07%	2007	40.00%	98%	100%	86%	$2,124	[5]	$216	89,400	[5]	[5]	[5]	[5]	[5]	[5]	[5]	[5]	N
Gaz Metropolitain	Québec, CAN	8.95%	2006	38.50%	97%	100%	94%	$2,358	$2,004	$1,886	205,903	[5]	[5]	[5]	[5]	[5]	[5]	A/A	2.13	Y
Alta	Alberta, CAN	8.51%	2007	41.00%	100%	100%	100%	$151	$131	$126	63,532	1%	35%	64%	0%	0%	0.31	BBB	2.44	Y
ATCO [6]	Alberta, CAN	8.51%	2007	37.00%	38%	30%	31%	$4,123	$2,861	$903	969,877	7%	45%	48%	0%	0%	5.90	A/A	3.52	Y
AVERAGES		**8.72%**		**37.45%**	**93%**	**93%**	**85%**	**$2,450**	**$1,679**	**$1,223**	**658,874**	**6%**	**27%**	**37%**	**0%**	**29%**	**6.17**	**A-**	**2.34**	
Median		**8.86%**		**37.75%**																
Minimum		**8.37%**		**35.00%**																
Maximum		**9.07%**		**41.00%**																
U.S. COMPANIES [7]																				
U.S. Companies Determined to be More Comparable to Enbridge and Union																				
Southwest Gas Corp.	Arizona, U.S.	9.50%	2006	40.00%	85%	85%	85%	$887	$775	$661	588,720	6%	18%	28%	0%	48%	2.28	BBB-	2.34	N
Atlanta Gas Light Company	Georgia, U.S.	10.90%	2005	47.93%	97%	81%	62%	$2,250	$2,068	$1,281	1,546,000	3%	3%	94%	0%	0%	5.98	BBB+	3.77	Y
Northern Illinois Gas Company	Illinois, U.S.	10.51%	2005	56.37%	86%	100%	85%	$1,753	$2,845	$2,423	2,166,000	1%	10%	42%	0%	47%	12.43	AA	2.32	Y
Michigan Consolidated Gas Company	Michigan, U.S.	11.00%	2005	39.31%	94%	94%	83%	$2,139	$2,101	$1,751	1,300,000	29%	29%	29%	0%	12%	3.82	BBB	1.96	Y
CenterPoint Energy Resources	Minnesota, U.S.	9.71%	2006	46.14%	48%	26%	48%	$929	$1,456	$23.98	521,199	30%	30%	40%	0%	0%	1.78	BBB	2.83	N
Public Service Electric Gas	New Jersey, U.S.	10.00%	2006	47.40%	98%	98%	40%	$5,932	$5,465	$2,212.12	1,700,000	4%	36%	60%	0%	0%	8.98	BBB	2.29	Y
Puget Sound Energy, Inc.	Washington, U.S.	10.40%	2007	44.13%	100%	99%	39%	$5,982	$3,372	$1,300	713,000	4%	22%	49%	0%	25%	3.07	BBB-	1.89	N
Wisconsin Gas LLC	Wisconsin, U.S.	11.20%	2006	50.20%	100%	100%	36%	$2,268	$1,258	$803	588,800	11%	11%	36%	0%	43%	3.45	A-	3.82	N
AVERAGES		**10.40%**		**46.44%**	**89%**	**85%**	**60%**	**$2,767**	**$2,418**	**$1,307**	**1,140,465**	**11%**	**20%**	**47%**	**0%**	**22%**	**5.22**	**BBB+**	**2.65**	
Median		**10.46%**		**46.77%**																
Minimum		**9.50%**		**39.31%**																
Maximum		**11.20%**		**56.37%**																

Company	Jurisdiction	Most Recent ROE	Date	Allowed Equity %	Parent Company: Percent Regulated Revenue	Parent Company: Percent Regulated Net Income	Percent Gas Distribution Revenue	Book Value (million $CAD)	Total Revenue (million $CAD)	Gas Distribution Revenue (million $CAD)	Total Gas Distribution Customers	Customer Mix [1]: Ind.	Customer Mix [1]: Comm.	Customer Mix [1]: Res.	Customer Mix [1]: Whlsl & Other	Customer Mix [1]: Trans-portation	Gas Volume Sold (10^9m^3)	Credit Rating (DBRS/ S&P)	Interest Cov. Ratio [2]	Un-bundled
Other U.S. Companies																				
Arkansas Oklahoma Gas Corp.	Arkansas, U.S.	9.70%	2005	41.04%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N
Arkansas Western Gas Company	Arkansas, U.S.	9.70%	2005	33.03%	23%	2%	2%	$413	$200	$200	151,000	26%	22%	34%	0%	18%	0.62	BB+	22.01	N
CenterPoint Energy Resources	Arkansas, U.S.	9.45%	2005	31.80%	51%	65%	48%	$929	$1,456	$24	521,199	30%	30%	40%	0%	0%	1.78	BBB	2.83	N
Public Service Company of CO	Colorado, U.S.	10.50%	2006	55.49%	99%	95%	33%	$6,183	$4,416	$1,464	1,255,330	8%	8%	35%	0%	49%	6.99	BBB	2.53	Partial
Southern Connecticut Gas Company	Connecticut, U.S.	10.00%	2005	51.28%	90%	99%	32%	$477	$364	$1,970	176,000	N/A	N/A	N/A	N/A	N/A	N/A	BBB+	2.35	N
Illinois Power Company	Illinois, U.S.	10.00%	2005	53.09%	89%	70%	13%	$2,711	$1,966	$630	430,000	19%	24%	57%	0%	0%	1.29	BBB+	4.68	Y
Interstate Power & Light Company	Iowa, U.S.	10.40%	2005	49.35%	96%	100%	20%	$2,650	$2,037	$417	239,372	6%	17%	24%	0%	53%	1.76	BBB+	4.37	N
Duke Energy Kentucky, Inc.	Kentucky, U.S.	10.20%	2005	54.45%	45%	45%	15%	$4,793	$1,874	$5,248	250,000	N/A	N/A	N/A	N/A	N/A	N/A	BBB+	12.52	Partial
Entergy Gulf States, Inc.	Louisiana, U.S.	10.50%	2005	47.52%	84%	61%	2%	$5,351	$4,270	$98	92,000	N/A	N/A	N/A	N/A	N/A	0.19	BBB	3.08	N
Baltimore Gas and Electric Company	Maryland, U.S.	11.00%	2005	48.40%	100%	100%	30%	$4,155	$3,499	$1,044	640,600	18%	32%	32%	0%	17%	3.26	BBB+	1.38	Y
Bay State Gas Company	Massachusetts, U.S.	10.00%	2005	53.95%	80%	68%	63%	$1,328	$363	$5,452	337,502	44%	20%	29%	0%	7%	2.34	BBB	2.25	Y
Consumers Energy Company	Michigan, U.S.	11.00%	2006	35.06%	99%	100%	41%	$8,372	$6,639	$2,755	1,714,000	N/A	N/A	N/A	N/A	N/A	8.75	BB	1.58	Y
Northern States Power Company - MN	Minnesota, U.S.	10.40%	2005	50.24%	100%	93%	19%	$5,234	$4,206	$864	418,994	22%	22%	43%	2%	11%	2.02	BBB	3.65	N
Central Hudson Gas & Electric	New York, U.S.	9.60%	2006	45.00%	66%	79%	16%	$845	$765	$181	367,000	N/A	N/A	N/A	N/A	N/A	N/A	A	3.76	Y
Orange & Rockland Utilities, Inc.	New York, U.S.	9.80%	2006	48.00%	100%	100%	29%	$989	$949	$675	125,589	5%	5%	63%		26%	0.35	A	2.64	Y
Vectren Energy Delivery Ohio	Ohio, U.S.	10.60%	2005	48.10%	81%	84%	60%	$933	$663	$401	318,000	47%	27%	27%	0%	0%	1.45	A-	2.46	Y
Oklahoma Natural Gas Co	Oklahoma, U.S.	9.90%	2005	46.76%	16%	14%	16%	$2,863	$5,436	$895	800,047	0%	9%	29%	8%	54%	10.74	BBB	2.16	N
PPL Gas Utilities Corp	Pennsylvania, U.S.	10.40%	2007	51.79%	69%	39%	5%	$7,244	$3,844	N/A	110,000	N/A	N/A	N/A	N/A	N/A	N/A	BBB	3.46	Y
South Carolina Electric & Gas	South Carolina, U.S.	10.25%	2005	50.75%	100%	100%	21%	$5,750	$2,775	$586	297,165	41%	28%	25%	0%	6%	1.23	A-	3.34	N
Virginia Natural Gas, Inc.	Virginia, U.S.	10.00%	2006	44.96%	97%	81%	62%	$525	$365	$1,702	264,000	4%	4%	92%	0%	0%	0.93	BBB+	3.77	Y
Avista Corp.	Washington, U.S.	10.40%	2005	40.00%	84%	89%	41%	$1,850	$1,386	$604	304,000	2%	19%	31%	25%	24%	1.78	BB+	2.12	N
Madison Gas and Electric Company	Wisconsin, U.S.	11.00%	2005	56.65%	103%	74%	40%	$794	$589	$237	138,000	4%	38%	55%	0%	3%	N/A	AA-	5.55	N
Wisconsin Public Service Corp	Wisconsin, U.S.	11.00%	2005	59.73%	100%	92%	31%	$449	$349	$515	306,293	10%	10%	30%	0%	50%	1.94	A+	3.60	N
Northern States Power Co-WI	Wisconsin, U.S.	11.00%	2006	53.66%	100%	101%	21%	$941	$853	$173	100,000	22%	22%	32%	5%	18%	0.50	BBB+	3.89	N
Wisconsin Electric Power Company	Wisconsin, U.S.	11.20%	2006	56.34%	100%	100%	19%	$5,199	$3,617	$685	452,600	12%	12%	39%	0%	38%	2.30	A-	6.12	N
Wisconsin Power and Light Co	Wisconsin, U.S.	10.80%	2007	54.00%	100%	100%	20%	$1,984	$1,626	$318	182,098	2%	19%	26%	0%	53%	1.23	A-	31.88	N
AVERAGES		**10.34%**		**48.48%**	**83%**	**78%**	**28%**	**$2,918**	**$2,180**	**$1,131**	**399,632**	**17%**	**19%**	**39%**	**2%**	**22%**	**2.57**	**BBB+**	**3.14**	
Median		**10.40%**		**49.80%**																
Minimum		**9.45%**		**31.80%**																
Maximum		**11.20%**		**59.73%**																
ALL U.S. - AVERAGES		**10.35%**		**48.00%**	**84%**	**80%**	**36%**	**$2,882**	**$2,238**	**$1,175**	**579,228**	**15%**	**19%**	**42%**	**2%**	**22%**	**3.33**	**BBB+**	**2.98**	
ALL U.S. - Median		**10.40%**		**48.10%**																
ALL U.S. - Minimum		**9.45%**		**31.80%**																
ALL U.S. - Maximum		**11.20%**		**59.73%**																

Company	Jurisdiction	Most Recent ROE	Date	Allowed Equity %	Parent Company: Percent Regulated Revenue	Parent Company: Percent Regulated Net Income	Percent Gas Distribution Revenue	Book Value (million $CAD)	Total Revenue (million $CAD)	Gas Distribution Revenue (million $CAD)	Total Gas Distribution Customers	Customer Mix [1]: Ind.	Customer Mix [1]: Comm.	Customer Mix [1]: Res.	Customer Mix [1]: Whlsl & Other	Customer Mix [1]: Trans-portation	Gas Volume Sold ($10^9 m^3$)	Credit Rating (DBRS/ S&P)	Interest Cov. Ratio [2]	Un-bundled

Notes:

[1] Customer mix is based on the best available information for each of the companies analyzed. For the most part, customer mix is based on volume of throughput per customer class. Where throughput information was not available, revenue by customer class was used. If neither of these types of information was available, CEA used number of customers by customer class. Enbridge's customer mix is based on revenue by customer type, based on Enbridge's 2007 test year rate case, EB-2006-0034, Exhibit C3, Tab 1, Schedule 1, p. 2. Union's customer mix is based on total 2007 forecast throughput for industrial, commercial, and residential customers, taking into account the approximate percentage of transportation throughput based on Union's 2006 MD&A. See EB-2005-0520, Exhibit C1, Summary Schedule 1, and Union Gas 2006 Annual Report.

[2] The mean interest coverage ratio for the U.S. companies is 4.8 times, but includes certain outlier data, such as 22 times for Arkansas Western Gas Company, 31.9 times for Wisconsin Power and Light Co, and 12.5 times for Duke Energy Kentucky. For this reason, CEA excluded the outlier data to arrive at the presented mean.

[3] While technically a gas distribution company, Enbridge classifies certain of it revenues as "transportation" revenues. Per Enbridge's 2006 Annual Information Form, "Under the transportation service, arrangement, a customer supplies natural gas at a TransCanada receipt point in western Canada or at a TransCanada delivery point in Ontario, and [Enbridge] redelivers an equal amount of gas to the customer's end-use location."

[4] Certain of Pacific Northern Gas, Ltd.'s information was presented at the holding company level only. For purposes of this table, that information is provided under PNG's West Division.

[5] Certain of Terasen Gas Inc.'s information was presented at the holding company level only. For purposes of this table, that information is provided under Terasen Gas Inc.

[6] Transportation volumes were unavailable for ATCO.

[7] Note: for U.S subsidiary companies for which financial statements were not available at the subsidiary level, CEA approximated book value and total revenue based on an estimate of the subsidiary's total contribution to the parent's consolidated operations. Estimates were made based on the best available data, which included customer numbers, revenue, and fixed assets.

EXHIBIT 2 - Complete Listing of U.S. Gas Distribution ROE Awards, 2005 to Present

State	Company	Case Identification	Date	Rate Increase ($M)	Return on Rate Base(%)	Return on Equity (%)	Equity /Total Cap (%)
Arizona	Southwest Gas Corp.	D-G-01551A-04-0876	2/15/2006	49.3	8.40%	9.50%	40.00%
Arkansas	CenterPoint Energy Resources	D-04-121-U	9/19/2005	-11.3	5.31%	9.45%	31.80%
Arkansas	Arkansas Western Gas Co.	D-04-176-U	11/2/2005	4.6	5.93%	9.70%	33.03%
Arkansas	Arkansas Oklahoma Gas Corp.	D-05-006-U	12/9/2005	4.4	6.61%	9.70%	41.04%
Colorado	Public Service Co. of CO	D-05S-264G	1/19/2006	22.5	8.70%	10.50%	55.49%
Connecticut	Southern Connecticut Gas Co.	D-05-03-17PH01	12/28/2005	26.7	8.85%	10.00%	51.28%
Georgia	Atlanta Gas Light Co.	D-18638-U	6/10/2005	0.0	8.53%	10.90%	47.93%
Illinois	Illinois Power Co.	D-04-0476	5/17/2005	11.3	8.18%	10.00%	53.09%
Illinois	Northern Illinois Gas Co.	D-04-0779	9/30/2005	54.2	8.85%	10.51%	56.37%
Iowa	Interstate Power & Light Co.	D-RPU-05-1	10/14/2005	14.0	8.68%	10.40%	49.35%
Kentucky	Duke Energy Kentucky Inc.	C-2005-00042	12/22/2005	8.1	8.10%	10.20%	54.45%
Louisiana	Entergy Gulf States Inc.	D-U-28035	7/6/2005	5.8	8.11%	10.50%	47.52%
Maryland	Baltimore Gas and Electric Co.	C-9036	12/21/2005	35.6	8.49%	11.00%	48.40%
Massachusetts	Bay State Gas Co.	DTE-05-27	11/30/2005	11.1	8.22%	10.00%	53.95%
Michigan	Michigan Consolidated Gas Co.	C-U-13898	4/28/2005	60.8	7.19%	11.00%	39.31%
Michigan	Consumers Energy Co.	C-U-14547	11/21/2006	80.8	6.69%	11.00%	35.06%
Minnesota	Northern States Power Co. - MN	D-G-002-GR-04-1511	8/11/2005	5.8	8.76%	10.40%	50.24%
Minnesota	CenterPoint Energy Resources	D-G-008/GR-051380	11/2/2006	21.0	7.54%	9.71%	46.14%
New Jersey	Public Service Electric Gas	D-GR05100845	11/9/2006	40.0	7.96%	10.00%	47.40%
New York	Central Hudson Gas & Electric	C-05-G-0935	7/24/2006	8.0	7.05%	9.60%	45.00%
New York	Orange & Rockland Utlts Inc.	C-05-G-1494	10/18/2006	12.0	7.99%	9.80%	48.00%
Ohio	Vectren Energy Delivery Ohio	C-04-571-GA-AIR	4/13/2005	15.7	8.94%	10.60%	48.10%
Oklahoma	Oklahoma Natural Gas Co	Ca-PUD-200400610	10/4/2005	57.5	8.74%	9.90%	46.76%
Pennsylvania	PPL Gas Utilities Corp	C-R-00061398	2/8/2007	8.1	8.44%	10.40%	51.79%
South Carolina	South Carolina Electric & Gas	D-2005-113-G	10/31/2005	22.9	8.43%	10.25%	50.75%
Virginia	Virginia Natural Gas Inc.	C-PUE-2005-00057	7/24/2006	0.0	7.83%	10.00%	44.96%
Washington	Avista Corp.	D-UE-05-0483	12/21/2005	1.0	9.11%	10.40%	40.00%
Washington	Puget Sound Energy Inc.	D-UG-060267	1/5/2007	29.5	8.40%	10.40%	44.13%
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-114	12/12/2005	3.8	8.88%	11.00%	56.65%
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-117 (elec.)	12/22/2005	7.2	8.83%	11.00%	59.73%
Wisconsin	Northern States Power Co-WI	D-4220-UR-114 (gas)	1/5/2006	3.9	9.97%	11.00%	53.66%
Wisconsin	Wisconsin Electric Power Co.	D-05-UR-102 (WEP-GAS)	1/25/2006	21.4	8.94%	11.20%	56.34%
Wisconsin	Wisconsin Gas LLC	D-05-UR-102 (WG)	1/25/2006	38.7	11.38%	11.20%	50.20%
Wisconsin	Wisconsin Power and Light Co	D.6680-UR-115 (gas)	1/11/2007	1.0	NA	10.80%	54.00%

Source: Regulatory Research Associates.

Regulatory Policy of Return on Equity

Review and Analysis of the Natural Gas Utility Sector

December 9, 2008

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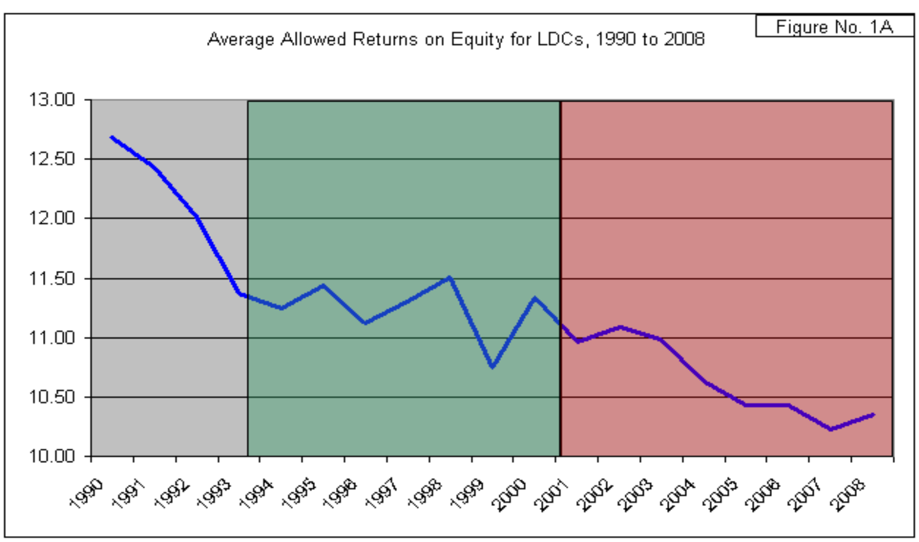
I. Executive Summary

The continued success of the utility sector to deliver natural gas safely and reliably depends upon a strong and viable infrastructure that will meet growing local distribution company (LDC) customer demands. The infrastructure development needed to address new and aging infrastructure relies heavily upon the ability of the industry to attract strong capital investment. As such, the American Gas Foundation (AGF) engaged Navigant Consulting Inc. (NCI) to examine the current processes utilized by the state public utility commissions to determine allowed returns on equity (RoE) for natural gas utilities in an effort to determine if the RoE rates being approved and established are adequate and sufficient to address U.S. pipeline and distribution infrastructure needs.

Given the diversity of state jurisdictions and policies, the effort undertaken for this study examines all state decisions over an extended period of time and relies upon statistical examinations of that large population of cases, informed by extensive interviews with financial analysts and senior industry executives, to identify and interpret trends and reasons for those trends and determine whether there is a perceived problem within the financial community. The core question posed by the study's mission statement and objectives, the impact of RoE decisions and policy on LDC infrastructure adequacy, is largely addressed through the interview process. This AGF study is intended to be an examination, and evaluation of the issues. While it observes various trends, impacts, and reasons for those impacts, it is up to other efforts to support the need for specific changes in individual proceedings. The study is intended as a backdrop to inform such efforts.

Background -- Trend in Allowed Returns

The phenomenon of steady declines in allowed LDC returns is clear, based upon an examination of some 377 PUC decisions nationwide, over the period from 1990 through 2008. In particular, the most recent period, from 2000 through 2008, has seen a steady decline from the mid 11 percent range to the low 10 percent range, with several recent decisions falling below 10 percent.



Further, the study analysis shows that this perceived decline was pervasive, with the overall distribution of returns moving to the lower levels. It also shows that there is a growing gap between the actual LDC equity ratios and the equity ratios that are actually recognized in rates – as is explained more fully in the study. Therefore, either approximately $2 billion of LDC equity investment is treated as if it is financed with debt, thus significantly reducing the recognized cost of that investment recovered in rates, or LDCs must adopt a higher debt level, which would increase financial risk. The LDC industry is generally facing RoE decisions and policies that result in returns around and below the 10 percent level.

Summary of Findings

Multiple interviews were conducted with financial analysts (both equity and debt) and senior industry executives (primarily chief executive officers of either LDC holding companies or the LDC subsidiaries of those holding companies). To encourage the candor of those interviews and to avoid singling out specific companies or jurisdictions, the interviews are summarized and explained in the body of this study, without attribution to specific individuals. Observations and conclusions include:

- Equity analysts expressed concern that when allowed returns drift below 10 percent, financial markets see that as a "red flag" that could turn substantial investment away from the industry. This risk is particularly valid now, according to the analysts, since changes in the population of large investors toward a greater weight of hedge funds and private equity firms allows large blocks of money to move much faster than in the past in departing from an industry.

- Equity analysts also stressed that if there are other indications of a favorable regulatory environment, one of mutual trust with collaborative development of comprehensive service and rate structures by the LDC and the regulator, the perception that low allowed returns indicate an unfavorable regulatory environment is largely ameliorated. However, there is a strong concern that a jurisdiction will work to develop such balanced, collaborative approaches, use that as a basis for low returns, and then, over time, erode the quality of the balanced approaches without revisiting return. This concern strongly validates the importance of open and honest dialogue between the utilities and their regulators, such that a mutuality of trust can stay in place long-term.

- Uniformly, the executives running LDCs are committed to safety and reliability of service, and thus will strive to invest what is required to maintain those objectives, as long as they are in the LDC business. However, low returns create incentives for them to avoid discretionary investment, and for their holding companies to exit the LDC business.

- It is only in jurisdictions where allowed returns have remained at higher levels more consistent with history, or where the LDC and its regulator have developed collaborative, more holistic approaches to services and rates supplanting traditional usage-based and cost-based regulation, that these incentives are not creating negative pressure on investment.

- Except for the jurisdictions where returns have remained higher, or where other arrangements have successfully supplanted more traditional regulation, the LDCs are experiencing increasing difficulty in competing for capital. The measure of such difficulty is not the relationship to debt cost, but the relationship to alternative equity investments.

- To date, much investment and even some merger and acquisition consolidation of the LDC industry have continued, but the continuation does not mean there is not a deep concern over allowed returns – rather, the various businesses are seizing opportunities as they present themselves, with the expectation that currently depressed allowed returns are a short-term phenomenon – the managers trust the system to "self-correct" over time. If that turns out not to be the case, the risk the industry and regulators run is a fundamental loss of trust in the regulatory system, one that would have a strongly negative impact on investment.

- Thus, although low returns have created a negative pressure on investment in LDC infrastructure, little impact has been seen to date. Public markets for capital have still been accessible for LDCs, in the opinion of the analysts and senior executives because of two factors: (1) the faith in the regulatory system recited above; and (2) the currently favorable tax treatment of dividends. However, continuing downward trends in allowed returns undermine the first rationale, and political uncertainty undermines the second. In addition, the recent large concentration of equity investment in such vehicles as hedge funds is expected to make financial markets quicker to react negatively if the current negative perceptions of LDC investment persist. In short, the threat to infrastructure adequacy is a looming threat, exacerbated by low returns, a threat that could be ameliorated by some corrective action.

- Various rate-design changes, in particular "decoupling," can provide some stabilization of LDC revenues, if properly applied. However, there is concern that regulators accord inordinate weight to these mechanisms' impact on risk when setting returns. Further, it is believed that many times there is a potential double-counting of the effect, since regulators apply a decrement to returns developed by reference to proxy companies that have similar de-risking mechanisms. Uniformly, the interviewees believed such decrements were ill-advised and unfair.

- At the same time, other risks of the LDC business have been increasing– specifically unfunded government mandates, precipitous run-up in the cost of critical materials such as steel and in the cost of contract labor, the regulatory risk of cost disallowance, especially in periods of rapid gas-cost increase, and asymmetric regulation of uncollected gas cost (e.g., paying interest on overcollections but collecting no interest on undercollections). Additionally, in the competitive, unbundled world of today's interstate pipelines, the risk of bypass for LDCs' highest-volume loads is pervasive. Thus, to the extent that decoupling might tend to stabilize revenues and thus ameliorate that area of risk, these other evolving risks offset or even reverse that effect. Further, unlike the revenue volatility addressed by decoupling (which volatility could go either way – reducing earnings or increasing earnings, depending on weather), these evolving risks are "one-way," strictly acting to the detriment of the LDC.

- The debt rating community is generally not deeply concerned with allowed return on equity, unless it gets low enough to threaten required debt coverage. That coverage cushion may be relatively smaller if the whole regulatory scheme enhances stability of revenues.

- However, the debt analysts do become concerned when allowed RoE drops to a level that forces company management to reorient investment into riskier areas to meet Wall Street expectations of growth. In other words, the allowed returns for the LDC must meet a risk-adjusted comparison with alternative investments, or the company's stockholders will tend to push reorientation to the point that its overall revenue profile becomes more volatile, and thus its corporate debt becomes less secure.

- There is much more depth in these and other observations in the body of the AGF Study. Overall, it is fair to say that there is widespread concern over the industry's ongoing ability to raise and retain capital. Generally senior executives feel that in the current market, returns below 10 percent are very problematic, that returns in the mid-10s are adequate to keep the businesses on an even keel, but not to win contested capital in competition with investments in other businesses with similar risk, and that returns in the low 11s, e.g., 11.25, can generally reach risk-adjusted parity with the investments with which LDCs must compete for capital.

- Clearly, the concerns raised by both financial analysts and senior executives in the industry have grown a great deal in importance in the current credit and financial turmoil. The rapidly evolving difficulties in raising all types of capital, both debt and equity, would suggest that any negatively perceived factor, such as inadequate or declining allowed rates of return, could exacerbate an already problematic situation in funding new infrastructure.

Reasons for Declines in Allowed Return

The study examines the two dominant methodologies used to set allowed RoE: Discounted Cash Flow (DCF) and the Capital Asset Pricing Model (CAPM), along with Equity Risk Premium (ERP), of which CAPM is a variation.

Very simply, the fundamental inputs to these longstanding methodologies have declined, so the resulting indicated rates of return have declined. In the case of DCF, the decline has been driven by reduced growth rates among proxy companies. In the case of CAPM (and ERP), the decline has been driven directly by the decline in interest rates over the last decade. While it is easy to identify the reasons the longstanding formulae are yielding lower results, the more difficult question is whether this effect highlights what may be infirmities in the methodologies, infirmities that were less apparent during periods of higher growth and higher interest rates.

This study explains the fundamental theory and operation of DCF and CAPM, with some generic calculations of the impact at today's input numbers. These calculations are based on a sample group of twelve proxy LDCs extracted from PUC staff testimony in a recent rate case (both the state and the LDCs are unnamed, to avoid any prejudicial reference to individual situations). Both DCF and CAPM yield average indicated returns on equity of 9.7 percent, over the twelve proxy companies. However, while the average is equal as between the methods, individual results varied by as much as 460 basis points.

These examples were useful in analyzing some of the issues presented by the application of DCF and CAPM.

- There was very wide diversity in the outcome indicated returns among the companies in the sample group: 740 basis points from the high to the low under DCF, and 630 basis points from the high to the low under CAPM. Given that the twelve-company proxy group consists of relatively similar LDCs, it is difficult to see a justification for these wide swings.

- For both DCF and CAPM, there is an inherent circularity in the use of proxy groups, in that if all the companies in the proxy group are similarly regulated, the Wall Street expectations for all of them will be similar – however, there is no test as to whether this uniform expectation is in fact adequate to compete for capital with non-LDC businesses having similar risks.

- As for DCF, there is a test performed in this study to determine whether the end result meets its own premises – that is, the DCF result is based on an investor expectation of a specific rate of growth in earnings and book value per share. It is demonstrated that, if retained earnings are the primary driver of such growth, the use of the DCF return as an allowed RoE does not generate enough cash to pay required dividends and still generate the assumed growth.

    - The 9.7 percent average indicated RoE would generate only 3.5 percent and 3.4 percent growth in book value and earnings per share, respectively.
    - However, within the development of the 9.7 percent, there is a determination that investor-expected growth is 6.4 percent, leaving a 3 percent deficiency in the growth rate.

- In the case of CAPM, as noted it is just a modified version of ERP – a fixed equity risk premium over risk-free debt is assumed to exist, regardless of the current interest-rate regime. The CAPM refinement to this assumption is merely to modify that fixed risk premium by multiplying it by a "Beta" factor to reflect a particular stock's volatility vs. the stock market at large.

- The open issue regarding either CAPM or ERP is whether a fixed equity risk premium is a valid assumption in the first place – many experts expect that risk premium to expand at low interest rates and contract at high interest rates.

- In other words, a broad school of thought believes the relationship between the cost of equity and the cost of debt is partial and tenuous. Even in Canada, where RoE is set by a formula tracking corporate bond rates, the "elasticity" or relationship between changes in the interest rate and changes in the RoE is less than one, presently 75 percent. Meanwhile, the Canadian gas industry strongly believes it should be even lower, probably about 50 percent.

- The result is that CAPM or ERP will give low RoE when interest rates are low, without taking account of the equity-vs.-equity competition discussed earlier.

Potential Adjustments

This study explores several potential adjustments to the return-setting process that could work to restore allowed RoE to the levels thought by the industry and analysts to be sufficient. These potential adjustments include:

- Broadening the proxy groups to reach beyond LDCs who are regulated under the same rules and methodologies as the company being examined. This would address the circularity of current proxy approaches.

- Using FERC decisions as a benchmark, recognizing that historically LDC RoE has generally been approximately 125 basis points lower than the RoE allowed to interstate pipelines. Maintaining this historic gap would help equilibrate the competition for capital between the LDC and the pipeline in the same corporate family.

- Considering variations on CAPM, such as the Fama-French Three Factor Model, which brings into the equation small-cap and high-growth companies to attempt to gain a clearer picture of investor expectations than is yielded by CAPM's averages.

- Restoring the growth deficiency identified under DCF. In the example, this would bring the indicated return up to 12.7 percent if 100 percent of the deficiency were restored. This is somewhat higher than the 11.25 percent to 11.50 percent the senior executives indicated is needed in the current environment, so methods could be explored to restore a portion of the deficiency, still assuming that some growth might come from other sources.

An overarching point is that regardless of the types of adjustments that might be sought, the industry must establish a credible case that real public damage can result from inadequate returns, in the form of inadequate investment, lost efficiencies, etc. While RoE decisions may be challenged in court, real ongoing relief requires a cooperative relationship with regulators that acknowledges the problem and indentifies the solutions.

In the case of an issue such as RoE, this is difficult, since any remedy means higher rates for consumers. However, the ultimate effect of allowed RoE being below the level required by investors may be a lessened ability to maintain and develop systems and this may result in inefficient natural gas service. Thus, substantial attention must be paid by the industry to establishing and maintaining the necessary credibility, through informal outreach, public presentations, and education such as this study.

II. Introduction

A. Background

Evaluating LDC allowed rates of return is a significantly different exercise than the review of pipeline allowed rates of return. Pipelines are subject to a single decision maker, the Federal Energy Regulatory Commission (FERC), while LDCs are subject to the jurisdiction of fifty different state public utility commissions (PUCs), and in some cases to regulation by the municipalities that they serve. In short, the approaches and the results among PUC decisions are much more diverse than is the case at the FERC, and the relationships between LDCs and their state regulators are more direct than those funneled through a central national venue.

Accordingly, this AGF study avoids singling out particular jurisdictions or companies, rather working to gain a common view across the industry of those factors or issues that do exhibit some commonality. Additionally, in part because there is not a single decision maker in the national LDC arena and in part because of the nature of AGF's mission, the AGF Study is intended as an examination of the facts and opinions it has elicited.

B. Process and Structure of Study

The body of the study consists of three major sections, Sections III through V.

In Section III, a quantitative analysis is combined with extensive interviews with financial community analysts and industry senior executives, to determine whether a pervasive problem exists or is emerging as to the rates of return being allowed to LDCs, and if there is such a problem what its implications might be for public policy. Heavy emphasis is placed here on the importance of credibility to the extent the industry claims the existence of a problem, with thoughts elicited from the interview process as to how such credibility might be enhanced.

In Section IV, to the extent that any problems in levels or trends in allowed returns have been identified in Section III, the processes and approaches used by PUCs that lead to such deficiencies or trends are identified and examined. Are there chronic forces at play that will result in long-term declines in allowed returns, or are current levels a short-term phenomenon?

Section V addresses possible changes or adjustments in observed processes, to the extent such changes or adjustments might be needed to respond to chronic issues that are identified in the study.

It is fair to say that Section III, grounded in observations of the rates of return actually being allowed and in the perspectives of the financial analysts who evaluate those companies and the senior executives of the regulated companies, is by far the most important aspect of this study. Developing the case that allowed returns have declined, that the levels at which they are being allowed are becoming problematic for the regulated companies, and that their problems will eventually become the public's problem, is critical as a threshold that must be crossed prior to questioning the specifics or the mechanics of the return-setting process.

III. LDC Allowed Rates of Return

As noted, the determination as to whether there has been a decline in allowed rates of return on equity and the development of a case as to whether such declines have long-term public-policy implications have been approached both quantitatively, through the measurement of allowed returns over time, and qualitatively, through an extensive series of industry interviews. Section A, below, presents the quantitative analysis. Section B then uses the results of the interviews to interpret the quantitative data.

A. Allowed LDC Rates of Return over Time

In order to measure changes in allowed returns on equity over the past several years, NCI gathered all reported LDC rate cases that were resolved from 1990 through mid-2008.[1] In total nationwide, there were 532 LDC rate cases closed during that 18.5 year period, spread fairly evenly over the many regions of the country. Of those 532 rate cases, many of them were resolved such that there was no stated rate of return on equity, usually as the result of a settlement. Accordingly, there were a total of 377 decisions in which a rate of return on equity was approved by the LDC's regulator. These 377 data points are broadly spread over the 18.5 year period examined, and thus give a reasonably clear picture of the trends that have emerged in state regulation of LDCs.

The NCI analysis of these trends is conducted in two parts. First, simple averages of the allowed returns have been calculated for each year in the 18.5 year period. These will be presented in Figure No. 1A, with an amplified view of the results for the most recent period, 2000 through 2008 in Figure No. 1B.

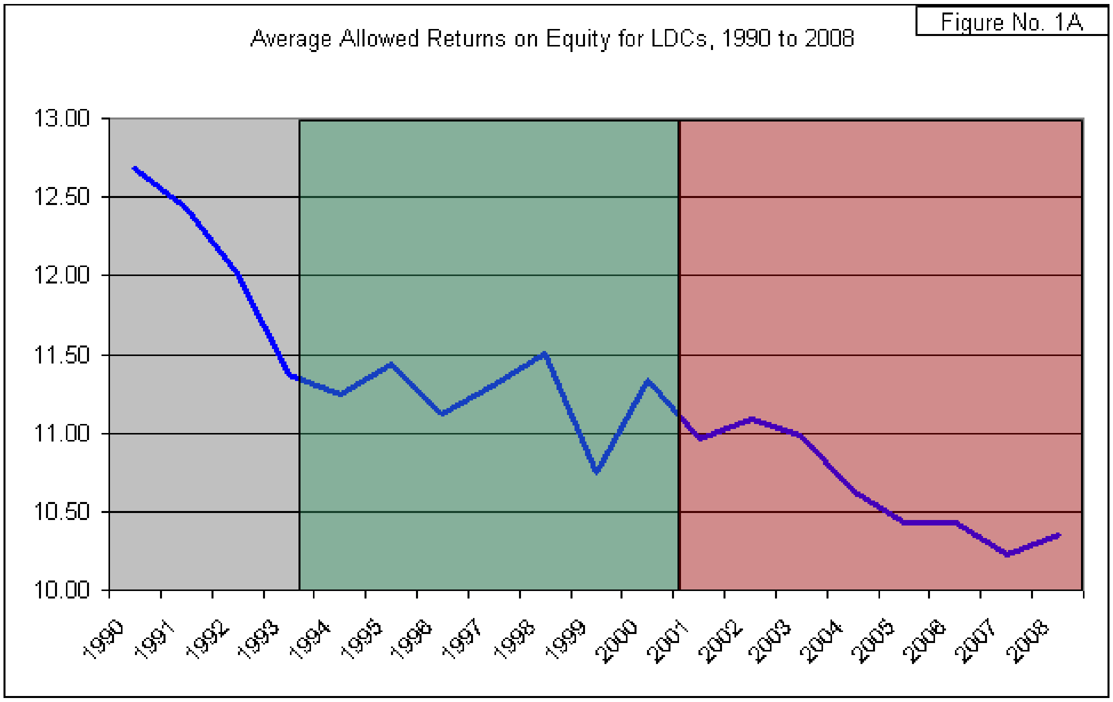
Then, recognizing that averages over diverse groups of data points might not tell the whole story, the progression of the distribution of returns is analyzed, for the Figure No. 1B period from 2000 through 2008. This progression is set forth in Figure Nos. 2A through 2C.

Then, in one additional observation, the common equity ratios to which these returns are applied have been observed over the same periods, comparing the equity ratios requested with those allowed, to determine trends in any gap between the two.

[1] Source: Regulatory Research Associates, SNL Financial, "Natural Gas, Past Rate Cases," July 2008—Data covers only the first half of 2008.

1. The Overall Average Allowed Returns, 1990 through 2007

As noted, Figure 1A measures the annual averaged RoE awards across all of the 377 rate cases decided on the merits during the 1990–2008 period. [2]



From average levels in the 12.5 to 13 range at the beginning of the last decade, allowed returns declined into a relatively stable range between 11.0 and 11.5, from 1993 through 2000. Then a steady decline began, which has resulted in today's observed levels approaching 10 percent. In fact, there have been various recent awards below 10 percent, as will be discussed below.

[2] Ibid, extracted and analyzed by NCI.

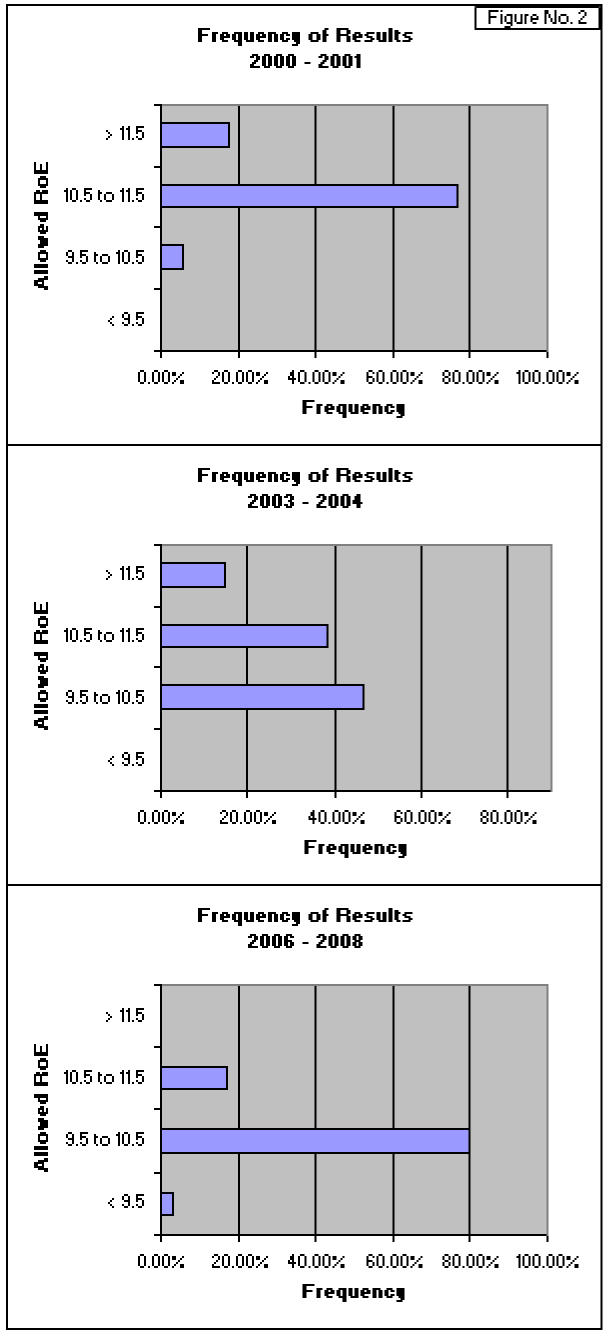
The steady decline that supplanted the relative stability of the 1993–2000 period may be seen clearly with an amplified, focused observation of the 2000–2008 period, as set forth below in Figure No. 1B[3]:

In part, the LDC industry has experienced a phenomenon similar to that experienced by interstate natural gas pipelines: Years of stable allowed returns within a fairly predictable band, followed by sudden exposure to returns significantly lower than those observed and expected at the time large past investments were made. Whether and how this could pose a significant challenge to new investment is explored in this study, primarily through the insights gained from the interview process. It is noteworthy and encouraging that there has been a slight uptick in the first half of 2008, with allowed returns averaging approximately 10.35 percent, but still well below historic levels.

[3] Same data as Figure No. 1A, stripped down to the 2000 – 2007 period only.

2. Distribution of the Allowed Returns

The pervasiveness of declines in allowed returns across the many jurisdictions studied is another factor that must be assessed – have the averages declined because of a few very low decisions, or has everyone's allowed return declined significantly? Figure No. 2 explores this question, examining the frequency of various ranges of allowed returns for three periods: 2000–2001, 2003–2004, and 2006–2008[4].



As Figure No. 2 shows, allowed returns in the first period, 2000–2001, were very tightly grouped in the 10.5 to 11.5 range – 76 percent of the allowed returns in those two years were within that range. A small group, about 18 percent, were higher, at levels above 11.5, and a much smaller group, about 6 percent, were in the 9.5 to 10.5 range. None fell below 9.5.

In the intermediate period, 2003–2004, we begin to see the decline, with the concentration moving down – to lower returns. The high (over 11.5) returns still constitute a measurable percentage, almost 15 percent of the total. However, the 10.5 to 11.5 category that dominated in 2000–2001 has dropped to 38 percent, and the lower 9.5 to 10.5 category has grown to 47 percent of total decisions.

The concentration toward significantly lower returns becomes fully apparent in the latest period, 2006–2008. Here, 80 percent of the allowed

[4] All data are from the same source and analysis as Figure Nos. 1A and 1B—Regulatory Research Associates, SNL Financial, "Natural Gas, Past Rate Cases," July 2008.

returns are in the 9.5 to 10.5 range (with more than half of those – 43 out of the 80 percent – being at or below 10 percent). We also see the emergence for the first time of a small percentage (one decision so far) below 9.5 percent.

Thus, there is no question that the decline in overall averages shown in Figure Nos. 1A and 1B is truly indicative of what is happening in most jurisdictions around the country. And, at a population of 377 rate case decisions, these are not anomalies.

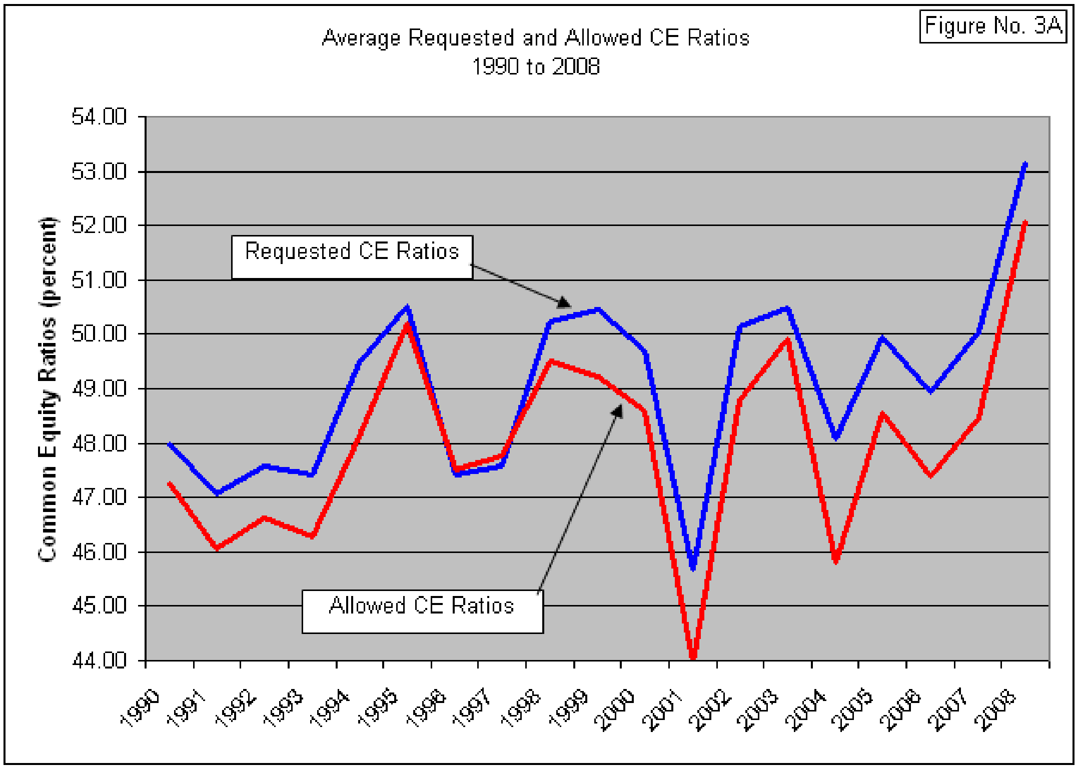
The fact of a decline in allowed returns on equity is merely that – a factual observation. The interpretation of such a decline – whether it is supportable, whether it is genuinely problematic for the industry or for public policy objectives, will depend on the actions of investors. Will they continue to invest in gas LDCs with these low returns or will they invest their capital in other businesses with similar risk that offer higher returns? An early indication of the answer to this question can be seen in the perceptions of the financial analysts and industry leaders who follow the industry.

3. Requested and Allowed Common Equity Ratios

Over the same 1990–2008 and 2000–2008 periods, the relationship between requested common equity ratios and the approved levels were examined. The common equity ratio is one of the most significant non-RoE rate elements in a rate case, in that a dollar of rate base that is deemed to be supported by debt, rather than by common equity, loses approximately 65 percent of its pre-tax earning power.[5]

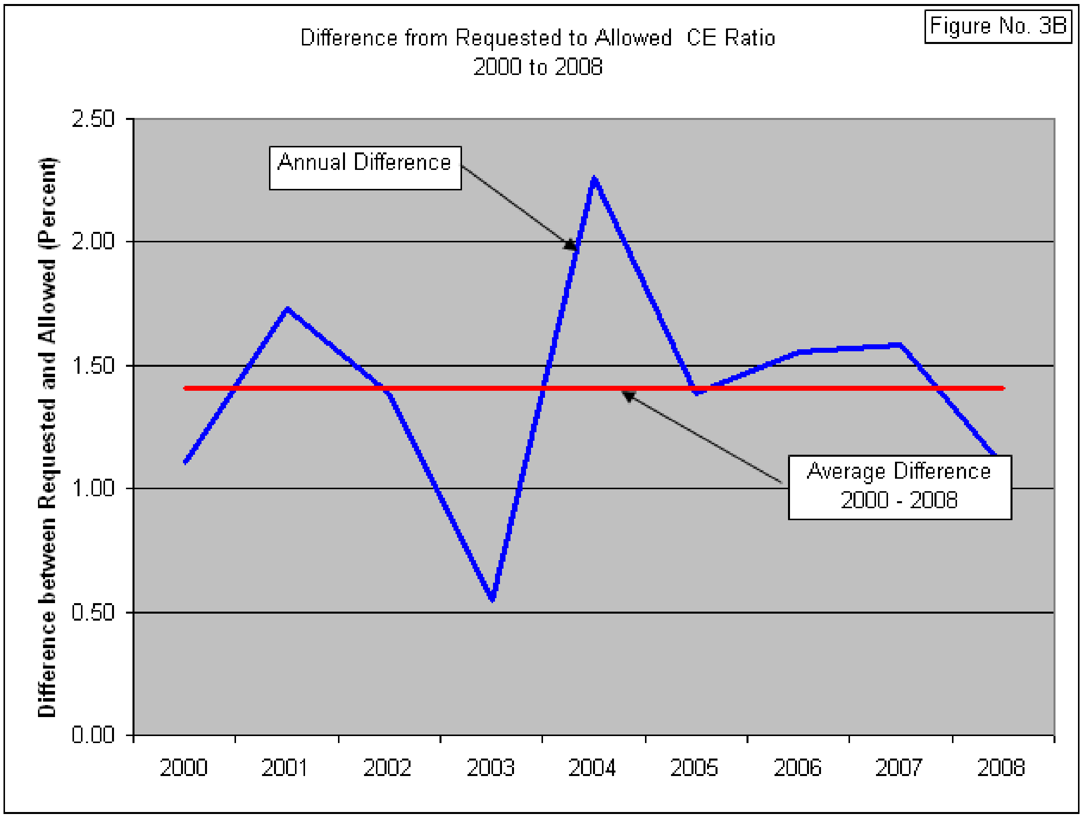
[5] Based on assumptions of an 11 percent RoE and a 6 percent interest rate, the pre-tax cost of a dollar of equity is approximately 17 percent, or 11 percentage points higher than the interest rate–thus according it only the debt cost rate under-prices the dollar of equity by 11 percent out of 17 percent, or 65 percent of its cost.

Figure No. 3A sets forth the average annual requested and allowed common equity ratios for the 348 LDC rate cases decided from 1990 through 2007 where a common equity ratio was stated. As with RoE, there were another 200 or so resolved rate cases wherein settlements did not state a number.



It is apparent from the plot that, beginning in the late 1990s, a broadening gap began emerging between the common-equity ratios represented by the LDCs themselves and those approved by regulators.

Figure No. 3B focuses on the 2000–2007 period, depicting the difference between requested and allowed common-equity ratios.



The annual decrement of allowed common–equity ratios below those requested by the LDCs has ranged between approximately 0.5 percent and slightly over 2.0 percent. The average for the eight-year period, represented by the red line, has been 1.41 percent.

This means that, on average, 1.41 percent of LDC rate base has been determined by regulators to be supported by lower-cost debt when the LDCs' own analyses indicated that it was supported by higher-cost common equity. Using a nationwide composite rate-base value for LDCs from the middle of the observation period,[6] this 1.41 percent difference would represent slightly more than $2 billion of investment that is "downgraded" from equity to debt.

When this happens, the LDC is left with a difficult choice: Allow equity investors to be chronically undercompensated, earning even less than the regulator's allowed return on equity, or refinance to higher leverage, thus incurring significantly higher financial risk. The end result of either course of action will be to disincent equity investment in the LDC.

[6] Per AGA Gas Facts, the 2004 net investment (plant minus accrued depreciation, plus other investments such as storage) was $168 billion for the entire US LDC industry. The total accumulated deferred income-tax balance was $24 billion, resulting in a net rate-base value of $144 billion. The 1.41 percent of rate base deemed to be debt rather than equity is thus worth $2.1 billion (1.41 percent of $144 billion).

B. Perceptions of the Industry – Implications for Utility Sector

As noted earlier, extensive interviews were conducted in 2007-2008 with equity analysts, bond rating agencies, and senior gas industry executives. The executives interviewed ranged from the chief executive officers of utility holding companies wherein the LDC business is one component, to the chief executive officers of LDC business units within holding companies, to chief executive officers of pure stand-alone LDC businesses. The geographic distribution of the selected executives spanned the lower–48 United States, from east to west and north to south. In the case of both the financial community representatives and industry executives interviewed, there is no further identification or attribution in this report, in order to avoid singling out any particular company or jurisdiction. The purpose of the interviews is to gain a sense of the industry's perception, and to gain the benefit of any insights that might have application beyond specific individual jurisdictions. Accordingly, the results of the interviews are presented within the context of thematic discussion of issues, rather than as the results of a poll.

The results are grouped around seven themes:

Theme 1 – Are allowed returns threatening capital availability?
Theme 2 – If returns are inadequate, why are you still investing?
Theme 3 – If capital gets tight, what are the consequences?
Theme 4 – How do investors view the importance of allowed RoE?
Theme 5 – How does RoE interact with other regulatory issues, such as decoupling, pass-through trackers, etc.?
Theme 6 – What is the state of LDC riskiness today, and is that level of risk reflected in allowed RoE?
Theme 7 – What sort of best practices were observed in the interaction of PUCs with the regulated LDCs?

Theme 1 – Are Allowed Returns Threatening Capital Availability?

External Competition: Certainly, favorable tax treatment of dividends has helped support utility stocks in general (although there appears to be evolving market concern over the potential for expiration of that treatment). However, concern over reductions in the allowed rate of return is beginning to show up in analyst opinions. Some of these expressions of concern see low returns as symptomatic of a broader unfavorable regulatory environment in the particular states involved, and some of the expressions of concern simply have to do with the absolute level of allowed return. One equity analyst opined that allowed returns below 10.0 percent "send up a red flag" that the LDC business may not be a good investment going forward. Additionally, analysts note that the investor population has changed substantially in recent years, with the growth of hedge funds, private equity firms, etc. These entities respond much more quickly to negative indications than did the institutional investors in the past. Thus, an overall perception that allowed returns are inadequate could, in the view of some analysts, cause a very rapid exodus of capital from the LDC industry.

Debt-rating analysts are somewhat less concerned, depending upon the quality of regulation in a jurisdiction. From a debt perspective, the return on equity constitutes the "cushion" of cash, the coverage ratio that protects debt from fluctuations in the business. Thus, debt-rating analysts weigh the overall stability of revenues in the totality of the ratemaking system against the security they would require from the return on equity. Like equity analysts, they see low allowed returns as potentially symptomatic of overall negative regulatory environments, which would concern them greatly. However, if they are satisfied that the rest of the ratemaking process is in fact fair and conducive to stability, the debt-rating analysts are less concerned over allowed return on equity.

One major concern raised by debt-rating analysts over low allowed returns is the impact it has on the rated company's incentives. Low allowed returns strongly incent a company to shift investment from the LDC business to higher-growth, higher-risk lines of business, in the words of one major bond-rating analyst, which then can increase the overall financial volatility of the whole company. Such increased volatility is of great concern to the debt analysts, and can rapidly lead to downgrades that then increase the cost and decrease the availability of debt.

Internal Competition: Within multi-business holding companies, it was indicated that discretionary investments in the LDC business must compete with investments in pipelines, in unregulated businesses, etc., all of which exhibit significantly higher returns than those being allowed in the regulatory process in most jurisdictions. A specific exception is California, where generically derived RoEs above 11 percent have kept LDC subsidiaries on a level playing field with the risk-adjusted returns from other business lines. In general it was indicated that allowed returns had to be above the 10.5 range to avoid causing major concern, and that it required returns above 11 percent for going–forward discretionary capital programs to be relatively secure. When allowed returns are observed or expected to drift below 10.0 percent, all of the senior executives expressed deep concern over the availability of internally competitive capital. Additionally, it was noted by at least one company that at a 10.0 percent return on book equity, there is inadequate cash generated to pay dividends while retaining enough to grow at the rate expected by investors. This phenomenon will be discussed later in Sections IV and V.

An additional issue raised by multi-state LDCs was the competition for capital within the LDC sector, but between jurisdictions. In other words, if the LDC serves two states and one of those states exhibits generally lower returns than the other, the low-return state may lose the competition for discretionary investment.

A point that was emphasized is that the internal competition for capital within holding companies is not driven at all by the cost of debt – it is driven by the expected return on equity to be derived from alternative investments. Thus, a holding company with a marginal cost of debt of 6 percent that is choosing between an LDC investment and a pipeline investment at 12.5 percent will require the LDC investment to match a risk-adjusted version of the pipeline investment, rather than some risk-premium-adjusted version of the cost of debt. Accordingly, it is the alternative equity investment, the 12.5 percent pipeline investment, which determines what the LDC must earn to be competitive. Based upon historic experience, this LDC equivalent investment would need to earn 11.25 percent or greater to meet that criterion.

An important point regarding the internal competition for capital was that most executives saw it not for the potential to deprive them of capital for needed projects–their companies will continue to invest as needed to maintain the health of their systems. Rather, they saw it as the front-line indicator, the "canary in the coal mine," indicating looming problems in external capital markets.

Today's current credit and financial turmoil clearly adds to the concern raised by the financial community. The rapidly evolving difficulties in raising all types of capital, both debt and equity, would suggest that any negatively perceived factor, such as inadequate or declining allowed rates of return, could exacerbate an already problematic situation in funding new infrastructure.

The overall summary of the analysts' and companies' assessments of the decline in allowed returns is that significant pressure is already being experienced in internally competitive investment choices, and that capital flight in public markets is a real possibility given changes in the investor population. Impacts are primarily seen in discretionary investment, in that the vast bulk of dollars invested by LDCs are required by the obligation to serve or by safety/integrity rules. As more than one senior executive put it, "As long as we are in this business, we will invest what it takes to run the business safely and reliably. However, we will not invest beyond what is necessary to do so, and we will increasingly look for ways to get out of the business if the observed declines in allowed returns are expected to continue."

Theme 2 – If Returns Are Inadequate, Why Are You Still Investing?

In spite of the deep level of concern expressed by the bulk of the senior executives, it is clear that each of them continues to compete for both internal and external funds, and that substantial discretionary investments are being promoted, sometimes successfully. This led to one of the most frequently asked questions in response to concern over low allowed rates of return: Why are infrastructure replacement projects, market growth projects, and LDC acquisitions still taking place, if the returns are inadequate? The answers from the senior executives were all grounded in a combination of the prevention of loss of opportunities and in a fundamental trust for the regulatory and legal process over time.

Effectively, the consistent answer was this: If an opportunity presents itself to extend into a new market, to enhance the long-term health of the system by replacing infrastructure, or to expand by acquiring another company, that opportunity has two characteristics: its availability is time-sensitive, and its impact is long-term, usually spanning multiple decades. If the opportunity is passed up because of what should be a short-term deficiency in allowed rates of return, the opportunity may be gone forever.

The corollary observation made by several of the senior executives, and by at least one equity analyst, is that low allowed returns today are being applied to investment made in past years, based upon the same level of trust in the system. Accordingly, the current steady decline in allowed returns runs the risk of undermining that trust, and threatens the credibility of the executives who promoted the past, now-embedded investment. It was made very clear that if there is not evidence of a reversal of the downward trend–that is, if the implicit belief that the regulatory and legal processes will bring allowed returns back to the more stable, higher levels that pertained in the 1993 to 2000 period, there is some point at which the combination of trust in the system and reluctance to let opportunities pass by will no longer sustain investment momentum. If that happens, the senior executives emphasized that the resulting frustration of new investment will take a long time to reverse.

Theme 3 – If Capital Gets Tight, What Are the Consequences?

As noted, the executives interviewed all committed that as long as they are in the LDC business, they will invest what is necessary to run their systems safely and reliably. Thus the question is raised as to what happens, what suffers, if low allowed returns cause LDCs to be unable to attract capital. The first victim is discretionary investment, projects such as infrastructure replacement that can have long-term operating benefits to customers, but that are not absolutely required for current system operation. Discretionary investment can also include extensions outside of a current franchise area to bring service to new customers not subject to the obligation to serve. It can include operational enhancements such as storage, technological innovation, etc., that can add long-term efficiencies to a system, but that are not necessarily required. While the senior executives running LDCs continue to promote and fight for this kind of investment, the interviews yielded multiple anecdotes wherein the investment was not forthcoming.

While the primary bases for a fair rate of return are the constitutional and statutory standards requiring fairness to investors, the important public-policy consequence of inadequate returns would be the frustration of productive investment. This frustration and its impact on consumers are much harder to demonstrate for LDCs than for pipelines, primarily because LDCs are required to make such a large portion of their annual investment. However, from the sense of the interviews, the slowing of investment and the negative impact of that slowing are real.

One additional long-term impact on consumers of inadequate returns and a consequent reaction of investment markets was explained by the equity analysts. They described a scenario in which a combination of deteriorating debt coverage and perception by rating agencies that low returns demonstrate a negative regulatory environment ultimately lead to a downgrading of LDC debt. Characteristically, such downgrades take an extended period of time to reverse. So even if allowed returns are restored to healthier levels in response to a downgrade, the consumer cost of higher interest rates and of reduced limits on leverage could continue for years. The bottom line of this discussion was that the best answer for regulatory agencies is to "get it right in the first place."

Theme 4 – How Do Investors View the Importance of Allowed RoE?

The investment community's perspective on allowed RoE was best represented by the analysts interviewed. As noted, they spanned both equity analysts and bond–rating analysts. All felt fairly strongly that allowed returns are drifting down to levels that cause some alarm, but the extent of that alarm varied depending on the analyst.

In essence, the least alarmed of the analysts felt that, if a low RoE is part of a holistic package of rate and regulatory features crafted in an atmosphere of cooperation and trust between the LDC and the regulator, such a package can work. For example, the use of stabilization mechanisms such as decoupling, in concert with various types of incentive ratemaking can – again if and only if they have been the collaborative product of both the LDC and the regulator – go a long way to offset the impact of low rates of return.

However, the concern raised even by the least alarmed of the analysts is that low returns might become established when such a cooperative environment exists, then subsequent regulatory action begins to chip away at the stabilization and incentive mechanisms that balanced the low return. Additionally, as was pointed out not only by analysts but by company executives, it only takes a single major disallowance to cause major long-term financial damage to an LDC.

Beyond the holistic view expressed above, analysts are concerned that a combination of allowed RoE below 10 percent, with a demonstrated continuous downward slide for the last eight years, will cause broad disenchantment with LDC investment that could take years to reverse. The observation, expressed earlier, that shifts in the population of investors toward hedge funds and private equity make large, sudden shifts away from an industry easier and more likely than in the past was considered important by the analysts.

Uniformly, both equity and debt analysts considered the allowed RoE to be an important barometer of the regulatory treatment of the LDC. The steady decline demonstrated earlier is thus a matter of major concern. Additionally, of course, there is concern over the absolute level of the allowed returns, as compared with comparable investments of equal risk, either internally or externally. As allowed returns have drifted to and below 10 percent, the perception is that many investments of equivalent risk could earn more.

Theme 5 – How Does RoE Interact with Other Regulatory Issues, Such As Decoupling, Pass-through Trackers, etc.?

As is discussed in Theme 4, a broad, balanced package of rate and regulatory mechanisms including such stabilizing features as decoupling and some "upside" potential through mechanisms such as incentive rates can – if constructed collaboratively between the LDC and the regulator in an atmosphere of trust – offset some deficiencies in allowed return. It was emphasized by some analysts and executives that the development of this collaborative approach leads to the healthiest long-term regulatory environment.

However, beyond the role of such other issues as part of a balanced package, there is a strong tendency by regulators to accord great weight to the "de-risking" impact of mechanisms such as decoupling, resulting in decrements in the allowed rate or return. However, where RoE is set by reference to a proxy group of other LDCs, it is important to ask whether the observed results from those LDCs already reflect the impact of the same mechanisms. That is, if a population of proxy LDCs demonstrates an investor-required RoE of, say 11 percent, and if all of those proxy LDCs already have decoupling mechanism in place, it is inappropriate to apply an additional decrement to the indicated return to reflect the introduction of a decoupling mechanism in the LDC whose rates are being set. Among those in the industry, this kind of return decrement in response to mechanisms that stabilize rates for both the LDC and its customers was a matter of concern. All of them believe that such decrements are ill-advised and unfair.

Theme 6 – What is the State of LDC Riskiness Today, and Is that Level of Risk Reflected in Allowed RoE?

LDC executives expressed significant concern over regulatory perceptions that their business is not particularly risky. In particular, statements made by the FERC in its Kern River decision[7] to the effect that pipelines are more risky than LDCs drew a number of negative comments. However, at least when the pipeline-LDC comparison was explored more fully, it became clear that the LDC

[7] *Kern River Gas Transmission Company*, Opinion No. 486, 117FERC61,077 (2006).

executives were not demanding that they be considered fully as risky as pipelines, but rather that differences in allowed return between the two types of businesses should be maintained at no more than their historic levels. That is, whereas interstate pipeline rates of return have remained solidly in the 12 to 14 percent range for 30 years, LDC allowed rates of return have, at least in the decade prior to the current decline, stayed in a range from 10.75 to 12.5 percent. This would imply a fairly sustainable difference in allowed return between pipelines and LDCs of approximately 125 basis points.[8] The concern is that now, in a period when pipelines are expected to be at least at the lower end of the historically observed range of allowed returns (12 percent), LDC returns are experiencing a decrement from that level of at least 200 basis points, and in some cases 250 to 300 basis points. If pipelines prevail in their arguments at the FERC to move somewhat higher, say to 12.5 percent, the historic LDC decrement would suggest a prevailing LDC allowed return of 11.25 percent. In the view of the LDC executives, no rationale has been put forward to justify the much larger decrements being experienced.

Effect of Rate-Design Changes: As noted earlier, many regulatory authorities point to rate-design changes such as decoupling, weather normalization, etc., as having the effect of stabilizing the LDC's revenues and thus tempering volumetric risk. There is fairly broad acknowledgment among the LDC executives that, where such mechanisms are in place and are properly designed, they do have such an effect of stabilizing revenues and of stabilizing consumer costs. Of course, they point out, stability is a two-sided coin – protection against the down-side of load loss is offset by the loss of the upside of load gain. Thus, it is not as if the LDC has been unilaterally relieved of a risk, rather it has given up an upside gain opportunity for some protection against a downside risk.

It is also very important that mechanisms such as decoupling or revenue normalization be properly designed. For example, an adjustment mechanism to make up for load loss may, as is done in some jurisdictions, merely attempt to raise rates in only the same class of customer where the load was lost. Thus, for example, the impact of a lost industrial customer might be turned into a rate increase for the remaining industrial customers, but not for any of the other customers of the LDC. When that happens, the effect can easily be a death-spiral of the particular sector of load, the new rate increase driving off more industrial load, resulting in a further rate increase and so on. Thus, before the risk impact of any such revenue stabilization mechanism is built into a rate of return deliberation, the full impact of the mechanism must be understood.

A particular concern voiced by several executives was the tendency of regulators to apply a decrement either explicitly or implicitly to the allowed RoE as the trade-off for a decoupling mechanism. While the regulators justify doing so by

[8] This basis-point difference is consistent with FERC's finding in Kern River, where a 50-basis point difference was applied because the two out of four proxies had some significant share of LDC business, along with pipelines and production.

the allegation that the LDC's risks have been reduced, the executives point out that such a decision is often "double-counting." Because LDC RoE is usually set by reference to the financial results of other, similar utilities, if those utilities themselves have revenue-stabilization mechanisms in place, the impact of those mechanisms is already subsumed in the basic data being used to set RoE. Thus, the executives say, any additional decrement is unjustified and unfair.

Evolving and Increasing Business Risks: Meanwhile, regardless of the impact of such mechanisms, LDCs are exposed to a variety of risks that have been steadily increasing. These risks include unfunded government mandates, precipitous run-up in the cost of critical materials such as steel and in the cost of contract labor, the regulatory risk of cost disallowance, especially in periods of rapid gas-cost increase, and asymmetric regulation of uncollected gas cost (e.g., paying interest on overcollections but collecting no interest on undercollections). Additionally, in the competitive, unbundled world of today's interstate pipelines, the risk of bypass for LDCs' highest-volume customers – industrial and power generation – is pervasive.

It is important to contrast the impact of these evolving risks with the impact of the revenue volatility that is addressed by rate-design changes such as decoupling. As noted above, revenue stabilization is a two-sided coin: Before it took place, volatility caused by factors such as weather could and did result in increased earnings from time to time, in addition to the periods when it led to deficient earnings. Conversely, the evolving areas of increased risk are "one-way." They work only to the detriment of the LDC without the potential for a compensating upside. These areas of evolving risk are discussed individually:

- **Unfunded Government Mandates**

  Both the Federal and state governments place multiple, expensive requirements on LDCs that must be paid for not by funds provided by those governments, but by either ratepayers or investors. The most recent large-ticket examples of these requirements surround inspection and integrity evaluation. For example, under the Pipeline Safety Improvement Act of 2002 as enhanced by the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, large scale and expensive inspections of transmission lines must be conducted, much more often than they were in the past. While much of the focus surrounding these statutes and the U.S. Department of Transportation regulations to implement them was on high-pressure interstate pipelines, there was actually an equal or larger estimated cost impact on LDCs. This is because LDC transmission lines – although far fewer and smaller than interstate transmission lines – are generally in "high-consequence" populated areas, thus triggering the most rigorous and costly requirements. The final DOT rule for distribution integrity management expected in 2009 would extend Federal inspection and integrity requirements to distribution systems themselves, at a cost estimated to be in the billions of dollars over the next several years.

As noted, every LDC executive interviewed reiterated the commitment to invest and spend the money necessary to ensure safety and reliability. On aging distribution systems, many of the costs required by Federal legislation may have been necessary anyway. However, the concern with uniform federally imposed mandates is that it can double the cost – performing the work required by Federal rules may not supplant the cost of inspections and replacements that would have gone on in the normal course of business.

The problem created by such unfunded mandates to incur operating expense and make substantial capital investment in inspections and replacements beyond what would normally be done is that they create costs that do not have any revenue-generation capability without a rate increase to customers. That is, investment in facilities that increase efficiency or add customers creates offsetting revenue that may preclude the need for a rate increase. However, required integrity investments must be recovered through increased rates, or will be absorbed by the LDC's investors.

None of the discussion questioned the advisability of uniform safety standards, but it was emphasized frequently that the full economic risk created by compliance falls on the LDC.

- **Increases in Construction Cost**

  The LDC industry nationwide has consistently invested between $4 billion and $5 billion annually, for the last decade. Much of this investment has been required for system integrity, to meet regulatory mandates, and otherwise simply to maintain safe, reliable distribution networks. Much of the investment has also, of course, been made for purposes of providing new gas service to consumers. The cost of the inputs for all of this investment has risen dramatically in recent years.

  According to anecdotal data provided by LDCs, individual components of LDC feeder line construction costs have increase 45–74% from 2002 to 2007:

  - 4”-8” valves – 45%
  - Steel fittings – 85%
  - 2”-4” steel pipe – 4%
  - 6”-12” steel pipe – 174%

In addition, contractor costs have risen dramatically, as demand for skilled services surged over the same period. Of course, regardless of construction cost, an LDC is theoretically allowed to include prudent investment in rate base. However, when costs increase at this pace, rate formulation can rarely keep up with them, even with a forward-looking test year. Additionally, to the extent that reduced allowed returns tend to place downward pressure on the LDC's ability to raise capital, radically increased size of those capital demands because of construction cost increases exacerbates the problem and thus becomes an ongoing risk increase for the LDC.

- **Gas-Cost Volatility**

Over the last few years, the wholesale market price for natural gas has experienced degrees of volatility never before seen. For example, during the last two winters, the spot price of gas at New York City has exceeded $30 per Dth, sometimes moving by double-digit amounts within one day. The primary industry benchmark wholesale price, Henry Hub, has generally been in a $7.00 to $8.00 range for some time, with significant daily and monthly volatility.

The impact of this volatility on LDCs has various aspects. Although virtually all LDCs do have a gas-cost tracking mechanism in their rates, the volatility of prices makes the forecast cost extremely difficult to predict. Thus, deviations between actual costs and forecast costs are frequent and large. If the deviation is an underrecovery, most LDCs are entitled to some manner of deferred recovery, but that recovery usually takes a full year and adds to the LDC's short-term financing requirements because in essence the unrecovered gas cost must be borrowed. If the deviation is an overrecovery, there is frequently a ratepayer backlash because of perceptions that the LDC was overcharging in past periods. Thus, volatility in gas prices has the dual effect of exposing large dollar amounts to extended recovery, financial cost and the attendant risk, combined with reaction and criticism among ratepayers and regulators when actuals deviate from forecasts, creating the risk of cost disallowance.

Most regulators view the LDC's ability to pass through gas costs as reducing risk. Certainly as compared with no such ability, such a reduction does occur. However, in RoE analyses that depend upon industry proxy groups, the risk-reducing effect of gas-cost tracking is a neutral factor, since all of the observed proxy companies have an equivalent ability. Meanwhile, it is important to recognize, as discussed above, that even a tracking mechanism cannot fully protect the LDC from the uncertainty and ratepayer backlash caused by large swings in gas cost.

- **Regulatory Disallowance**

  Of all the regulation-related risks, disallowance of costs is the most direct in its impact on the LDC's risk profile. Some costs such as contributions, economic development, dues and donations which are essential to the LDC's role as a member of its community, are routinely disallowed in some jurisdictions. This creates an automatic, chronic inability for the LDC to earn its allowed rate of return, despite the apparent business necessity of the expenses. The interviewees indicated that this sort of disallowance is never considered or compensated for in the model used to determine the allowed return.

  The larger risk, alluded to in discussing gas-cost volatility, is the unexpected disallowance of single major cost items, such as gas cost deemed to be excessive or the cost of treating certain supplies to meet quality specifications. The interviews cited at least one example of such a disallowance occurring in an amount equal to the LDC's full allowed return to investors for the year. That disallowance was ultimately reversed in court years later, but the financial market's perception of the risk remained. In general, PUC review of an LDC's gas cost and purchase policies is often after-the-fact, allowing attacks on past decisions with the benefit of hindsight. Accordingly, LDC sales service with its substantial gas-purchase obligation includes a good degree of risk in today's market.

- **Asymmetric Regulation of Uncollected Gas Cost**

  A factor affecting a number of LDCs, both in the risk/cost of gas-cost underrecoveries and in the pressure on their short-term financing capability is the treatment of the time value of deferred underrecoveries. Among LDCs recently surveyed as to the structure of their gas-cost,[9] it was learned that 62 percent either receive no interest on the recovery of unrecovered gas cost or they receive a lower time value of money than is paid on overrecoveries. This asymmetry adds to the financial risk entailed by gas-cost volatility and the probability of underrecoveries.

- **Risk of Bypass**

  LDCs have for years been faced with the potential to lose their largest individual customers, generally large industrial and power-generation loads. If such customers have access to the same interstate pipeline that serves the LDC, they frequently enjoy the economy of size to be able to justify connecting directly – eliminating the LDC as the middleman. This is especially true when the LDC's regulators have required a "tilt" in cost allocation and rate design in order to cause the large customers to

[9] This survey, conducted in 2005 for the American Gas Association, received responses from LDCs in 60 percent of the state jurisdictions, including all of the large, populous states.

subsidize smaller residential and commercial customers. According to the interviewees, market realities have largely forced regulators to phase out such subsidies – it has been recognized that maintaining the cross-subsidies runs the risk of losing the loads altogether.

For many LDCs, such large individual customers are still significant contributors to the LDC's total revenue profile. Yet, even if all rate cross-subsidies have been phased out of the charge to the large customer, it is still frequently cheaper to connect directly to a pipeline. Pipelines themselves are much more accessible and easily used by an industrial customer than was true in the past. FERC open-access, interconnection, capacity release, contract segmentation, and business-practice standardization have all served to make direct access to a pipeline much more feasible for an end-user than it was before those policies matured. In addition, many large marketers offer "asset management" services, whereby the end user can sign up for pipeline capacity, then hire the marketer to buy gas, manage the capacity, and make sure the correct quantities always reach the end user. Such marketers also manage large portfolios of capacity released by multiple shippers, sometimes including even the LDC's own pipeline contracts. These portfolios can allow them to serve the end user directly from the pipeline, without the end user ever being required to contract for pipeline capacity.

In short, bypass directly from pipelines to large end users has always been a risk for LDCs, but today the ease and feasibility of accomplishing that bypass are greater than ever. The impact of this risk varies widely across LDCs, depending on the degree of their reliance on large individual-customer loads.

Inability of New Business Margin to Sustain Growth: Another factor raised by some of the LDC executives, which goes partly to risk and partly to the inability of the LDC business to offset that risk, is the margin contribution from new business. When an LDC is compelled to add a new customer in its franchise area, the rules vary widely as to how the new customer's margin contribution will be set. In most jurisdictions, efforts have been made to avoid subsidization of the new customer by existing customers, so mechanisms such as capital contributions, limited-term surcharges, etc., have been used to ensure that the new customer fully covers its cost. However, this situation is at variance with many capital intensive businesses, where growth in demand actually gives a disproportionately large margin contribution. Basic capacity is put in place, and then marginal growth using that capacity has a low marginal growth and high marginal profitability. For LDCs who can barely cover the marginal cost of adding a new customer, growth does not offer this kind of contribution, which could make up for deficiencies in the earning capability of the embedded business. Thus, it is particularly important that the allowed rate of return on the embedded business be adequate.

<u>Theme 7 – What Sort of Best Practices Were Observed in the Interaction of PUCs with the Regulated LDCs?</u>

As noted in Theme 4, the financial community views with great favor those regulatory situations where the LDC and the regulator have worked together in an atmosphere of mutual trust, to craft balanced packages of rate and regulatory mechanisms. Such fairness and balance can offset some apparent deficiencies in allowed return since, first, such packages tend to stabilize revenues to reduce earnings volatility, and, second, where there is an atmosphere of mutual trust, the financial community can be confident that the regulator will work with the LDC to maintain financial integrity, regardless of the challenges faced – when there is a real problem, the LDC will be able to get timely relief. This is in sharp contrast to the more adversarial relationships that exist in some states, wherein the LDC faces a constant uphill struggle to achieve balance and stability in its regulated business. Thus, a definite "best practice" in both the regulator and the regulated is the development of collaborative initiatives that can foster an atmosphere of mutual trust. While this report does not generally single out specific jurisdictions, an exception is made here – according to analysts, New Jersey is an example of a state where such balance has been achieved.

Additionally, as noted in Theme 1, California has maintained mechanisms that periodically establish generic LDC returns in the state, using multiple analytical approaches to arrive at returns which the regulated LDCs have generally regarded as fair and adequate, at levels in excess of 11 percent. These were the sole LDCs interviewed that did not express concerns over capital constraints. Clearly some degree of trust and openness has evolved in the state to allow this to happen, and it is possible that other states could benefit by observing California.

IV. Reasons for Declines in Allowed RoE

There is no doubt that allowed returns on equity have steadily declined, as is measured and observed in Section III. Are the declines the result of changes in approach by regulators, or the result of the normal operation of the approved mechanisms, in the face of input numbers that have simply declined? For the most part, the reason appears to be the latter – simple evolution of the fundamental input data has been allowed to pull returns down through the mechanical operation of the favored regulatory tools for setting returns. A consistent theme sounded by industry executives in commenting on this evolution is the need for some sort of "human intervention," or benchmarking against actual investor expectations, to recalibrate the use of the approved mechanisms. This is often referred to as a "market-based reality check."

In particular, it is worth noting that the cost of debt built into rates is generally based upon an actual measurement of the debt instruments held by the subject utility, with the benefit of stated interest rates and other cost factors. In contrast, the cost of equity is always an estimate, based upon models that attempt to approximate investor requirements. Investors' actual requirements (the conceptual equivalent of an interest rate on a bond) are not directly measured. Accordingly, it would appear to be very important to find ways to ground RoE outcomes in something more than theoretical constructs that are merely assumed to mirror investor expectations.

There are three dominant mechanisms used to set allowed returns on equity in the regulatory arena: Discounted Cash Flow, Equity Risk Premium, and the Capital Asset Pricing Model. As a first step, each of the mechanisms will be explained, along with a brief description of the dynamics of the inputs to each. Then the interplay among the three mechanisms will be examined.

A. Discounted Cash Flow

Discounted Cash Flow, or DCF, is widely used throughout the state regulation of LDCs and is the exclusive method used at the FERC to set pipeline rates of return. DCF is an attempt to measure the expected cost of money for the typical investor in the stock of the regulated company. It does this by assuming that the market price of the stock is equal to the net present value of a perpetual future dividend stream, discounted to today's value at the investor's cost of money. This assumption is then turned into an equation to solve for the investor's cost of money in terms of the current stock price, the current dividend rate, and the expected rate of growth in earnings or enterprise value. Although the underlying math is fairly complex, the ultimate formula that results from the process is extremely simple:

$$\mathbf{K = D/P + g}$$

Where "K" is the investor's cost of money, "D" is the annual dividend, "P" is the stock price, and "g" is the rate of growth.

These factors are not generally directly available for an individual LDC, since most LDCs are subsidiaries of larger companies and thus are not publicly traded. So the normal practice is to use "proxy" companies, or a population of publicly traded companies with significant LDC business that are considered similar enough to the LDC in question to be used as benchmarks in determining what investors will expect out of the LDC in question.

Probably the best way to demonstrate the operation of the DCF formula by a PUC and to discuss its implicit issues is to use a real-world example. The example used here is taken from an actual LDC rate case in 2007, without naming the LDC or the jurisdiction. Similarly, the specific proxy companies used in the analysis have been designated simply as "LDC 1" through "LDC 12," to avoid any prejudice arising from their representation here. Based on the author's experience, this extract from a PUC staff witness's analysis (shown below in Figure No. 4) is quite typical of the application of DCF in the state regulatory arena throughout the United States.

DCF Example from PUC Staff Exhibits **Figure No. 4**

Company	13 week Avg. Price	Current Dividend	Dividend Yield	Average Growth [10]	Cost of Equity
LDC 1	$42.75	1.64	3.84%	5.9%	9.8%
LDC 2	$31.80	1.28	4.03%	6.2%	10.2%
LDC 3	$31.47	1.46	4.64%	4.4%	9.1%
LDC 4	$52.69	1.52	2.88%	6.6%	9.5%
LDC 5	$48.89	1.86	3.80%	2.9%	6.8%
LDC 6	$48.45	1.42	2.93%	4.7%	7.7%
LDC 7	$26.59	1.00	3.76%	4.2%	8.0%
LDC 8	$38.47	0.98	2.55%	9.4%	12.0%
LDC 9	$31.73	0.40	1.26%	11.3%	12.6%
LDC 10	$38.24	0.86	2.25%	6.6%	8.9%
LDC 11	$27.76	0.70	2.52%	11.6%	14.2%
LDC 12	$33.65	1.37	4.07%	3.1%	7.2%

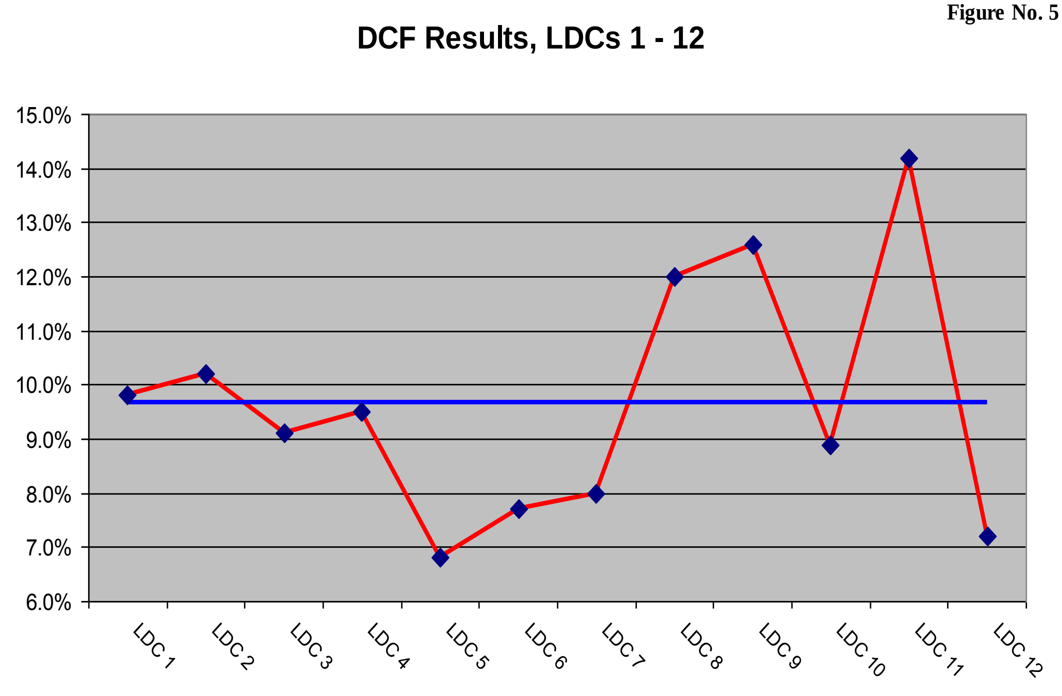
The DCF calculation described above is applied by first determining a dividend yield rate for each proxy (dividend divided by market price), then adding to that dividend yield rate the expected rate of growth in earnings and dividends. Then the resulting costs of equity for the proxy companies are used as a range within which the company at issue is placed, based on its relative risk. Typically, without compelling evidence to the contrary, a company is placed at the median, the midpoint, or the average of the range. In the range shown above, from a low of 6.8 percent to a high of 14.2 percent, the average would be 9.7 percent.

In other words, a typical PUC application of the DCF methodology using current market numbers yields the sort of below 10 percent result about which the industry interview subjects express such concern. Are there aspects of this calculation that argue for reexamination of the methodology? There are at least three observations that suggest something beyond this DCF calculation would be appropriate.

[10] The Growth rates used are averages of four different calculations, including historic and projected growth in earnings per share, historic and projected growth in book value per share, and growth in assumed retained earnings. The end result is intended to represent the rate of growth in earnings and dividends that investors could reasonably expect from each proxy company.

First, there is simply the very wide diversity of the results, for twelve companies that should ostensibly be quite similar. Graphically, as presented in Figure No. 5, this wide diversity is quite apparent:

Figure No. 5



From the lowest result to the highest result, there is a difference of 740 basis points. Interestingly, there is very little similarity between the "proxy" results shown for these twelve individual companies, and the actual allowed rates of return determined by their own PUCs. In short, there is a real question as to whether this genuinely defines the range of real investor expectations that can simply be averaged to yield a fair return. The potential for shortcomings in this analysis have been less apparent in the past when depressed stock prices gave high yield rates, and when various measures of growth pushed the numbers somewhat higher. However, today, arguing that a measured cost of money ranges from 6.8 percent to 14.2 percent, and that therefore an average of 9.7 percent is appropriate would appear to be a misuse of averages.

The second observation as to this DCF approach is its inherent circularity. As noted, the approach set forth in Figure No. 4 is very typical of PUC applications of the methodology, both in the calculation itself and in the selection of the proxies. If all the proxy companies are LDCs whose returns are set the same way, then measuring historical performance and Wall Street expectations of growth will always reflect the outcome of the same methodology that is being applied to measure that outcome. So if the DCF methodology is yielding an inadequate result, the inadequacy would affect most or all of the proxy companies as well. Thus, even if accurate, DCF would measure the cost of money necessary to compete for capital with other LDCs, but would not measure the ability of the whole industry to compete for capital with other businesses with similar risk not subject to this regulatory regime.

The last observation goes not to the theory or calculation of the DCF cost of money, but to the use to which it is put. By developing a cost of equity based upon stockholder expectations in the stock market, at best the methodology yields the individual investor's expectation of long-term return on a share of LDC stock. The next step, applying this number directly as a return on book equity, creates a potential disconnect – it is now limiting the specific cash return on rate base that will be available to achieve the investor's expectations. That cash be sufficient? To answer this question, we have to assess two factors: The LDC's ability to pay its current dividend and the LDC's ability to achieve the growth in earnings and net book that is required by investors. If we assume that the primary driver of growth in earnings per share or net book value per share is the growth in retained earnings, it is possible to test the DCF-derived return for adequacy.

Figure No. 6 first derives the average values for each of the building blocks and for overall return, for the proxy group from Figure No. 4. Then it adds one more piece of data, the average book value per share for the proxy group (which is 19.22 as of the time of the other data used in the analysis, for a market-to-book ratio of 2.0). In essence, we are building the hypothetical "average" LDC on which the return is based. A dividend yield of 3.3 percent is added to a growth rate of 6.4 percent, for a cost of equity of 9.7 percent.

Test for Growth Deficiency						**Figure No. 6**
Price	Dividend	Yield	Growth	Cost of Equity	Average Book	Market-Book
$37.71	$1.21	3.3%	6.4%	9.7%	19.22	2.0
EPS	Dividend	Remaining Earnings	Growth in Book	Marginal EPS	Growth in EPS	Growth Deficiency
$1.86	$1.21	$0.65	3.5%	$0.063	3.4%	-3.0%

But then we come to the second line of Figure No. 6. What happens when the 9.7 percent return is applied to book rate base? The book value of equity rate base is only $19.22 per share, as opposed to a market stock price of $37.71. Thus, 9.7 percent times rate base will generate earnings of $1.86 per share. Those earnings must first pay the current dividend of $1.21, leaving 65¢ per share to fuel growth. How much growth will it fuel? The 65¢ represents a 3.5 percent growth in the net book value of $19.22. As a rate of growth in earnings per share, we would multiply the 9.7 percent rate of return times that 65¢ of new equity, generating 6.3 cents of new earnings, or a rate of growth in earnings per share of 3.4 percent. According to the original study, however, investors require a rate of growth of 6.4 percent–there is an apparent growth deficiency of 3.0 percent, between the required rate and the average of the actual book and earnings growth rates. This could be problematic – the effect over time would be for the LDC to miss investor expectations by a significant amount, causing declines in the stock price. The natural reaction of the LDC's owners – indeed, their fiduciary responsibility to their investors – would be to invest in other activities that would make up the deficiency. Investment would flow away from the LDC.

Many of the issues raised over the use of DCF in setting returns have to do with the original purpose of DCF analysis – and the way it is still used by major investment analysts. That original purpose was and is for the comparison of alternative investments, rather than to derive an absolute level of investor-required return. For example, DCF is quite useful for distinguishing the twelve proxy companies from each other, regardless of the absolute level of return that might be appropriate. Its accuracy as to such absolute levels has been assumed more than demonstrated. It is this tension that underlies many of the concerns over the intersection between DCF financial theory and application of that theory in a cost-based regulatory arena.

Possible approaches for addressing the various observed concerns regarding DCF analysis are discussed in Section V – Potential Changes and Adjustments.

B. Equity Risk Premium and the Capital Asset Pricing Model

Equity Risk Premium (ERP) is an approach that simply assumes the cost of equity will track the interest rates for various types of debt. The realized returns in equity markets are compared over time with concurrent interest rates, to determine the premium that must be earned by stockholders in order to attract them from less risky debt to more risky equity. Sometimes the ERP is measured from "risk-free" debt, generally long-term government bonds; sometimes it is measured from various high-quality corporate bonds.

The Capital Asset Pricing Model (CAPM) is really just a further refinement of ERP. Whereas ERP determines a premium generally required of equity markets, CAPM translates it to the individual stock, using a measure of that stock's volatility vs. the stock market at large.

It is not necessary to produce representative studies to show the role of ERP and CAPM in the current decline in allowed returns. No one questions that interest rates have declined substantially over the past decade, so any method that holds a constant relationship between equity and debt costs will result in substantially reduced returns on equity.

Equity Risk Premium

ERP is more often used as a check than as a primary source of allowed returns. However, probably its more significant impact is that even when ERP is not technically the method being applied, it is clearly behind the regulatory psychology surrounding returns on equity, regardless of how they are derived. In times of deeply reduced interest rates, regulators and consumers expect utility allowed returns to be reduced equally substantially (although, unfortunately, this logic does not always fully work in the other direction, when interest rates are high).

There are two issues often raised as to this assumption. First, the relative size of an equity risk premium over debt cost has been the subject of much debate-especially as to how that premium behaves in different interest-rate regimes. The argument is made that the ERP expands during low-interest rate periods and contracts during high-interest-rate periods. As a practical matter, this was certainly the approach taken by regulators in the early 1980s, when the prime rate was in the high teens.

It is also the approach that has evolved over time in Canada, where since the mid-1990s returns on equity have been set by automatic formulae that track long-term bond interest rates. As those interest rates change, the allowed return on equity is adjusted by just 75 percent (the "elasticity factor") of the change, not by the full movement. This has the effect of shrinking the ERP when interest rates are high and expanding the ERP when interest rates are low. There is considerable debate in Canada over the size of the elasticity factor. Most of the industry and some prominent former regulators have suggested that the factor should have been lower-probably at approximately 50 percent. However, the concept is the same – an acceptance that market-required returns on equity do not track interest rates percent-for-percent.

The other issue, less empirical than the observed movement of the cost of equity as compared with interest rates, is the basic competition for capital in which the cost of equity is the measure of competitiveness. As the 2006 INGAA paper referenced earlier pointed out, and as was emphasized repeatedly by both senior executives and analysts in this AGF Study effort, the cost of equity is an opportunity cost issue, whether in the open market or in the capital-allocation process of a multi-business holding company. Essentially, if an investor's only alternative to investing in an LDC stock is to buy a bond, the required risk-premium to move the decision in favor of the LDC equity is important. However, a bond is generally not the only alternative investment – in the actual market, the investor can choose among multiple equities of which the LDC stock is one. In making this choice, the only important factor is what the investor's earnings would have been in those alternative equity investments. In other words, in the case of the stand-alone LDC the equity investor is free to move his or her capital to other businesses with that offer better returns without a significant increase in risk.

Similarly, if a holding company is solely making a choice between investing in its LDC subsidiary and issuing or retiring debt, the difference between the expected LDC earnings rate and the interest rate on the debt in question is relevant and important. However, if the holding company is allocating a fixed capital pool (consisting in part of borrowings based on achieving a particular corporate capital structure), the holding company is making choices among competing investments, requiring the LDC to meet the risk-adjusted return from the alternatives. If the holding company could earn 12.5 percent by investing in a pipeline and, in the holding company's judgment, the risk adjustment between the pipeline and the LDC is the historically observed 125 basis points, the LDC must earn 11.25 percent to compete – regardless of what the holding company's debt cost may be.

Capital Asset Pricing Model

As noted, CAPM is primarily a refinement of ERP, in that it adjusts the risk premium for the individual stock's observed relationship to the stock market as a whole. This relationship is defined by the stock's Beta, or volatility. Like DCF, CAPM is characterized by a great deal of background mathematical analysis (its original creators won the Nobel Prize for it), but a very simple ultimate formula:

$$\mathbf{K = Rf + \beta \ X \ ERP}$$

where "K" is the equity investor's cost of money, "Rf" is a risk-free interest rate (usually long-term Treasury bills), "β" is the individual stock's volatility vs. the overall stock market, and "ERP" is the equity risk premium for stocks generally.

The obvious issue with CAPM is that if "Beta" is less than 1.0, the company being examined will be assumed to need a lower than average risk premium. Many utilities exhibit Betas below 1.0.

Figure No. 7 sets forth the Betas for the twelve proxy companies examined in Section IV A.

Figure No. 7

Company	Beta
LDC 1	0.32
LDC 2	0.59
LDC 3	0.92
LDC 4	0.62
LDC 5	0.65
LDC 6	0.77
LDC 7	0.58
LDC 8	0.66
LDC 9	1.20
LDC 10	0.59
LDC 11	0.70
LDC 12	0.90

Of these twelve major LDC holding companies, only one has a Beta above one. There is also the same sort of extremely wide diversity observed in the DCF comparison, with Betas ranging from 0.32 to 1.20. This would mean that for an ERP of, for example, 7.1 percent, [11] the indicated returns for the proxy LDCs would vary by as much as 625 basis points.

Assuming a risk-free rate and a Market Risk Premium of 4.66 percent and 7.08 percent respectively,[12] the resulting returns are as shown in Figure No. 8. The average is coincidentally the same as the average of the DCF results, but the high is 100 basis points lower and the low is 200 basis points higher than the DCF results – and the individual companies vary quite widely, by as much as 460 basis points (LDC 11, at 9.60 percent here, but 14.20 percent per the DCF study).

Figure No. 8

Company	Beta	Cost of Equity
LDC 1	0.32	6.9%
LDC 2	0.59	8.8%
LDC 3	0.92	11.2%
LDC 4	0.62	9.0%
LDC 5	0.65	9.3%
LDC 6	0.77	10.1%
LDC 7	0.58	8.8%
LDC 8	0.66	9.3%
LDC 9	1.20	13.2%
LDC 10	0.59	8.8%
LDC 11	0.70	9.6%
LDC 12	0.90	11.0%
	Average	9.7%

As is discussed above with regard to ERP, CAPM follows a lock-step relationship with interest rates that does not reflect equity-to-equity competition based on opportunity cost. Thus, as with DCF, CAPM can be a useful tool for the comparison of similar investments, but may be of questionable use in deriving an absolute cost of capital.

[11] The widely accepted Ibbotson-Sinquefield average for 1928 through 2005 is 7.08 percent. Some other sources, such as Damodaran Online, quantify a lower MRP, at or below 5 percent.
[12] The MRP of 7.08 percent is per footnote 10, the 4.66 percent Rf is per Damodaran Online.

Obviously, if the growth objectives quantified in the DCF analysis are to be met, a 9.7 percent return derived by CAPM is just as deficient as a 9.7 percent return derived with DCF.

V. Potential Changes and Adjustments

As is noted earlier, adjustments could be made to each of the prevailing methodologies, or somewhat different approaches taken, to respond to perceived deficiencies. This section itemizes what those changes might be and the challenges in implementing such changes.

A. Broaden Proxy Groups

Along the same lines as the debate recently resolved involving pipeline proxy groups (see B. below), LDCs could look farther afield than their own industry for proxy companies. The standard to date for the selection of proxies has always started with the notion that the comparable companies must be regulated utilities, primarily in the gas business. However, this standard implicitly causes the circularity discussed in Section IV. Since the key distinguishing factor is risk, LDCs and regulators could be well served to identify unregulated infrastructure companies with risk levels analogous to those of the LDC. The measured market expectations for those unregulated companies would then be undiluted by the results of regulatory policy.

B. Use FERC Decisions as Reference Point, Maintain Historic Gap

There have been several references to the historic 125 basis point difference between pipeline returns and LDC returns. One option would be to maintain that difference. This approach has been uncertain to fix all deficiencies unless pipeline rates of return were maintained at their historic levels in the 12 to 14 percent range. The Kern River decision, cited earlier, resulted in a return on equity of 11.20 percent – application of the 125 basis-point difference to that number would fall below 10 percent, but the pipeline industry has been adamant that the Kern River decision was itself an inadequate rate of return.

The key issue in the pipeline industry has been the composition of proxy groups, with pipelines seeking the inclusion of pipelines organized as master limited partnerships (MLPs), in order to repopulate the proxy groups. On April 17, 2008, the FERC issued a statement of policy and a reopening of the Kern River case, allowing such inclusion of MLPs. The statement of policy requires some adjustment to the assumed long-term growth rate for the MLP members of the proxy group, but overall, it appears that the resulting rates of return will be restored to approximately the 12 percent level.[13] Thus, something on the order of

[13] FERC Docket No. PL07-2.

10.75 percent to 11.00 percent would be implied for LDCs, if the FERC level is maintained and the pipeline-LDC gap is maintained as well.

C. Variations on CAPM, Particularly Fama-French

The Fama-French methodology is a variant of CAPM that uses more than the broad, full-market average results for stocks to derive a risk premium. It includes some proportion of high-growth and small-cap stocks, thus generally resulting in significantly higher returns than unadjusted CAPM would have. Some LDCs, both in the U.S. and Canada, have tried to gain acceptance of Fama-French in their own proceedings, with mixed but very limited success.

D. Restore Growth Deficiency in DCF

The inherent deficiency of growth below that assumed to be necessary in the DCF formula should be a fertile ground to explore. Regulators can argue that growth can come from sources other than retained earnings. However, regulators appear generally to accept the notion that a buildup of retained earnings is necessary to sustain growth in either book value or earnings per share.

The adjustment to compensate for the deficiency is simple – in the example, where growth is 3.0 percent below expectations, the 3.0 percent is simply added to the indicated return, for a total of 12.7 percent (if full restoration of the growth deficiency is deemed appropriate). In the Figure No. 6 example in Section IV, using the 12.7 percent return on book equity would yield $2.43 of earnings, which, when netted for the $1.21 dividend, would leave $1.22 of retained earnings. Investing the $1.22 in the LDC business at a return of 12.7 percent would yield 15.5¢ of new earnings, which is 6.4 percent of the original $2.43 of base earnings. In other words, the $2.43 of earnings per share is growing at 6.4 percent, as it is supposed to. Net book, which started at $19.22 per share, grows by $1.22, which is also a 6.4 percent rate of growth.

How does this 12.7 percent indicated return reconcile with the earlier observations that something lower, perhaps 11.25 percent, should be adequate? The reconciliation could be based upon restoring only part of the growth deficiency, assuming that some factors other than retained earnings from return-times-rate base do contribute – 11.25 percent would represent restoring just over half of the growth deficiency.

The central rationale of the growth-deficiency restoration is that the application of a market-based DCF result to book rate base does not generate enough money to pay required dividends and generate the growth that the regulator itself has determined is expected by investors. However, there are counter arguments to making the adjustment – most notably the argument that rates are being set to sustain market share values above book. The tension between this concern and the concern that returns be set to put LDC investment on a level playing field deserve a full policy discussion with regulators.

E. Thresholds for Adjustments to Be Contemplated by Regulators

The mechanics of changes, whether they are changes in the proxy group, references to pipeline returns, or adoptions of new methodologies such as Fama-French or growth-deficiency restoration, all require a willingness and enthusiasm on the part of regulators that is not apparent in most jurisdictions. The challenge for the industry is to generate sufficient credibility and confidence in state commissions that a steady decline in allowed returns is causing a looming public-policy problem. Certainly, each LDC can go forward based on the statutory right to a fair return, but moving toward significant changes will probably take more proactive help from regulators than can be gained from winning a court case. Clearly, the lesson learned through the analysis process was that the jurisdictions with an atmosphere of trust and collaboration appear to be fostering the healthiest LDCs.

The bottom line in all instances is credibility. If credibility is generated within the state commission, more positive changes are likely to happen, although there is no guarantee the state commission will incur the political heat of increasing rates. If credibility is generated with legislators and courts, there is more likely acceptance of the types of analyses contained within this AGF Report. In some notable instances (one leading one being the FERC conference in 1998), it has been the face-to-face interaction of senior executives and analysts with regulators, in a public arena where critics are free to criticize, that has generated enough credibility to foster significant change in rates of return. Most LDCs already have such discussions at the state level, but the trend in allowed returns suggests that more are needed.

Return on Equity:

Allowed Returns for Canadian Gas Utilities

A Discussion Paper Developed by the
Canadian Gas Association

May 2007

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Executive Summary

The natural gas system is a foundation upon which improvements in Canada's environmental performance will be based while ensuring reliable and affordable energy services for Canadians. It is critical that this system remain highly flexible and functional.

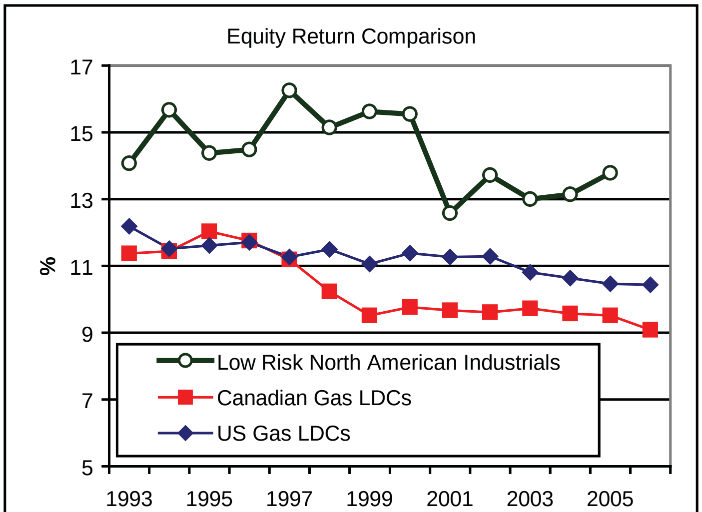
In 1995 the economic regulation of natural gas utilities in Canada underwent a significant change with the introduction of a generic formula-based approach to determining the "fair return" for shareholders of these companies. These returns are regulated to ensure that, in the absence of open and competitive market forces, they remain fair and reasonable. The Supreme Court of Canada set out the fundamental requirements that a fair or reasonable return on capital should meet. The National Energy Board summarized these requirements as follows:

- A fair return should be comparable to the return available from the application of invested capital to other enterprises of like risk;
- A fair return should enable the financial integrity of the regulated enterprise to be maintained; and
- A fair return should permit incremental capital to be attracted to the enterprise on reasonable terms and conditions.

Taken together these requirements, in effect, can support the conditions for and provide a prospective test of, the continued economic strength and viability of the natural gas pipeline and distribution industry in Canada.

Since 1995, all three requirements have come under increasing pressure as a result of regulatory decisions, significant changes in the Canadian investment and bond markets, and changes in the broader North American economy.

In particular, comparable returns to Canadian natural gas utilities have fallen well below the required standard. Canadian gas utilities have seen their allowed returns drop 100 to 170 basis points[1] below those of their US peers, and 300 to 600 basis points below the average returns for low risk North American industrial enterprises.



Source: Canadian Gas Association, S&P Insight

Formula-based allowed returns have now declined to the point where they are no longer providing a fair return to investors and are sending a strong signal that the continuation of a sustainable, optimal natural gas system in Canada is at risk.

To correct this deficiency it is recommended that Canadian energy policy makers and regulators:

i. Recognize the necessity of a long-term, low-cost, optimal and robust natural gas delivery infrastructure, oriented towards future energy sustainability, rather than the minimal, short-term least cost, and constrained system that risks emerging from a prolonged period of depressed allowed returns.

ii. Take immediate steps to eliminate the formula-induced deficit between allowed returns for natural gas utilities in Canada and those of other comparable North American natural gas utilities and low risk enterprises.

iii. Seek to provide appropriate capital market signals to investors by having allowed returns formulas include direct consideration of comparable natural gas utility and low risk enterprise returns in North America.

iv. Convene a national review of the generic formula approach, its ability to meet the requirements of the fair return standard, and respond to the significant changes seen in the economy, government bond market, capital markets and stock markets since 1995.

Introduction

Natural gas delivery utilities in Canada operate as regulated monopolies with their operating expenses, capital investment projects, the rates they charge their customers, and the return they can earn for their shareholders all requiring approval by a regulator.

This regulatory arrangement recognizes that from both a cost and service efficiency standpoint there need only be a single delivery system for natural gas in any region (electricity delivery is treated similarly). Once the first utility installs natural gas services to a community, street or house, it would not be efficient for society as a whole that other companies build a competing delivery system. This type of market structure, termed a "natural monopoly", occurs when the cost of serving the market is minimized by a single firm offering the service. A natural gas delivery infrastructure, once installed, represents a large sunk cost for the utility, which is not easily moved or sold if business conditions deteriorate.

Unlike non-regulated businesses, many of a gas utility's decisions as well as many of its financial parameters are determined by a regulatory board, in lieu of open market forces. As part of its regulated franchise agreement the utility has an "obligation to serve" customers in its franchise area and is expected to make investments to fulfill that obligation. In serving customers the utility is not allowed to set its own prices/rates, or invest in whatever capital assets (buildings, machinery & equipment, and engineering infrastructure) it wishes, nor is the utility allowed to freely earn whatever return the market allows. The utility's rates, including any portion that provides a return to the shareholders of the business, and its terms and conditions of service are determined by a regulatory board.

In return for these constraints the utility is allowed to remain a monopoly, and receive a "fair return" from a more stable regulated revenue stream. Its monopoly position protects the utility from the threat of direct competition within its franchise area; although some natural gas transmission lines do face competition (e.g. NEB regulated transmission lines and segments of the system in Alberta). Notwithstanding its monopoly over gas distribution, a natural gas utility can lose business if customers relocate to outside the franchise area, cease operations due to economic circumstance or decide to switch to another competing energy supply form, usually electricity.

In an open competitive market, economic forces automatically determine prices, reward innovation, promote competition, attract new investment and ultimately determine the return that companies and their investors receive. In a regulated monopoly, these open market forces are replaced by regulatory board decisions and these automatic linkages are lost. As a result it becomes more difficult to balance incentives for investment, innovation and the development of an optimal long-term, low cost natural gas grid with the short-term price impacts on consumers. An unbalanced, regulated market can create pressure towards a short-term, least cost, minimum system if incentives for sustaining investment are inadequate. This process is now underway for Canada's natural gas utilities.

This paper will:

- Establish why a robust, long-term low cost natural gas infrastructure should be a public policy goal;

- Explain why a fair return is important for natural gas infrastructure and what a fair return is;

- Demonstrate how and why the fair return standard is not being met in Canada; and,

- Recommend actions to be taken by policy makers and regulators.

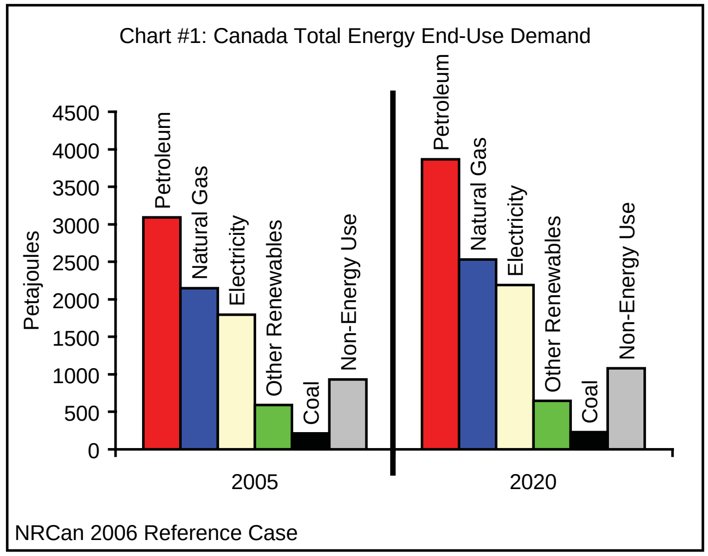
Section 1: The Public Interest, Sustainability and Canada's Natural Gas System

In the first instance the public's interest in a sustainable energy system centers on meeting their basic needs for heating, hot water, hot food, lighting and transportation. Canada has abundant, multiple energy resource options, including natural gas, to not only meet the basic energy service needs of its population but to go well beyond the basics.

Canada's energy capabilities support a highly developed industrial economy whose production provides Canadians with a standard of living and quality of life that few other nations can match. The National Energy Board (NEB), Natural Resources Canada (NRCan), the National Round Table on Environment and the Economy, the International Energy Agency, and the U.S. Energy Information Administration, all expect natural gas will continue to play a critically important role in meeting the needs of Canadians and the world for decades to come.

In Canada, the natural gas delivery services industry provides almost six million customers with clean, efficient natural gas energy delivered directly to homes and businesses through over 400,000 kilometres of underground pipe. The sector's impressive record of over 99.999% reliability reflects the over $30 billion of investment made in the critical infrastructure needed to establish a system that most customers simply take for granted.

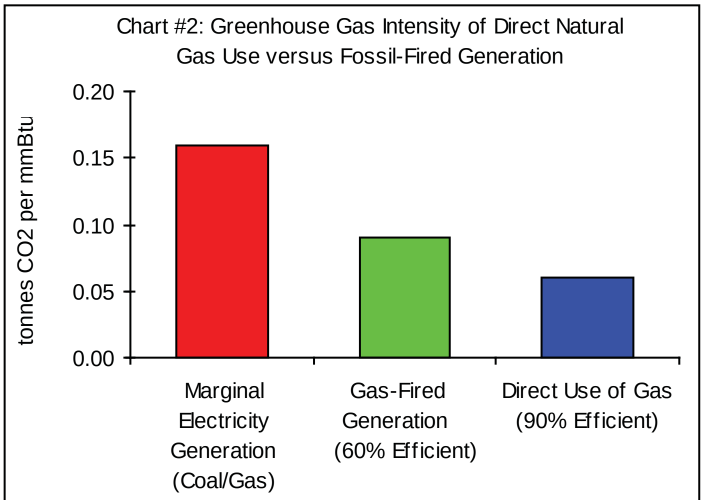
A sustainable energy future for Canada will rely heavily on the natural gas system. NRCan reports that, in 2005, just over 24% of end-use energy demand in Canada was met by natural gas. By the year 2020, NRCan expects this picture to remain virtually unchanged with Canadians still depending on natural gas to meet a quarter of their end-use energy demand (see Chart #1).



Similar studies performed in the United States and Europe all show that natural gas will remain a significant, and in some cases growing, part of global energy supply and end-use for the foreseeable future.

Canada's multiple energy capability affords us the option to choose and use the best energy mix for our situation, now and in the future. The benefits of such "optionality", and natural gas' contribution to it, are readily apparent in a number of areas. Consider the following examples.

In New Brunswick, where much of the electricity is generated by oil and coal fired power plants, direct use of natural gas provides a valuable option. It takes more energy – about twice as much – to produce the electricity used for home or water heating than if consumers were to simply switch to the use of natural gas directly in furnaces and water heaters. Use of natural gas for cooking and clothes drying extends this advantage further. In addition, switching to natural gas reduces emissions by cutting the need to use a higher emitting source for electricity generation (see Chart #2)[2].



Source: CGA, Vattenfall AB

In Manitoba and Quebec the option to choose between abundant natural gas and hydro-electric resources provides strong environmental and economic benefits. These provinces' electricity grids are connected to neighbouring provinces and states that rely upon oil, coal and natural gas power plants. The option to use natural gas directly for their heating requirements allows these provinces to increase hydro-electric power exports to their less flexible neighbours. Those neighbours can then supplant their own use of higher emissions fuels providing an overall improvement in environmental impacts. In addition, Quebec and Manitoba gain the export revenues from the sales of the hydro-electric power.

For British Columbia, the option to increase the direct use of natural gas in homes and businesses will help limit imports of mostly coal-fired electricity. This will help decrease emissions related to the province's electricity consumption and improve its electricity self-sufficiency.

In all regions of the country natural gas can be paired with ground source heat pump technology in geothermal heating/cooling applications. Integrating these two energy options creates a highly efficient system. This helps reduce electricity demand during peak summer periods, a time when air conditioning load can contribute as much as 25% of the peak electricity demand. In addition, gas fired geothermal heating and cooling provides secure heating/cooling, even in extreme cold or in the event of an electrical disruption due to storms, brown or black outs or other interruptions.

A strong natural gas distribution system affords Canadians the option to increase their use of the over 1400 kilo tonnes of bio-methane generated by landfills each year. Landfill bio-methane, once cleaned, provides a renewable source of natural gas for a variety of applications. Environment Canada reports that just over 22% of the available bio-methane is captured and used providing a 6.6 mega tonne reduction in equivalent CO_2 emissions. Examples of current facilities that use bio-methane from landfills include:

- Power generation at a Cascades paper mill that uses bio-methane supplied from a 13 km pipeline from the nearby Sainte-Sophie landfill.

- Electricity and heat generation at the CanAgro greenhouse operation in Vancouver.

The option of natural gas for use in light duty vehicles, such as taxis and small delivery trucks, produces 20% fewer greenhouse gas emissions than their conventional gasoline counterparts, decreases NOx emissions by more than 35%, and SOx emissions by more than 45%. Similarly in heavy duty vehicles, switching to natural gas engine technology from diesel cuts NOx emissions by more than 80%, allows for a 17 tonne reduction in GHG emissions per year for transit buses, a 7.6 tonne reduction for refuse trucks, and a 35 tonne per year reduction for tractor trailers.

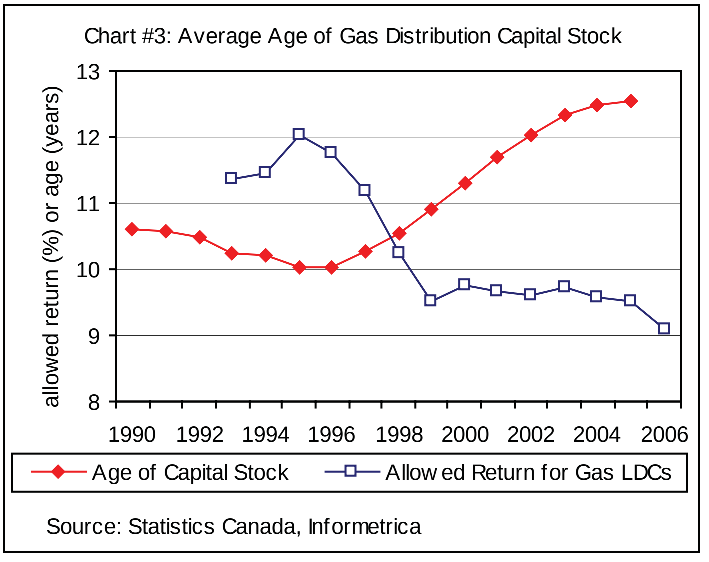
By using the latest natural gas based distributed micro-generation technology, it is now cost effective to use small-scale natural gas power generation in our homes, offices, and other buildings such as hospitals and shopping centres, to provide highly efficient heat, electric power, and cooling while easing the strain on the power grid.

Ensuring that these options continue to exist and that Canada continues to benefit from natural gas in our economy requires a robust and highly functional natural gas grid. Canada should be investing in an optimal grid to provide the energy services to handle an uncertain future with flexibility.

Moreover, with a solid natural gas framework at its core Canada will have the critical enabling platform to allow intermittent energy forms such as wind and solar energy to become useful components of the energy system. Natural gas broadens the range of possibilities in Canada's sustainable energy future in addition to meeting the needs of society today.

Natural gas utilities are always thinking about the future. Canada's gas distribution utilities make annual investments (over $1.3 billion in 2005) to meet their obligation to serve current and new customers, maintain reliable natural gas distribution services and enable the energy future that Canadians expect. To do so natural gas utilities require competitive access to capital in order to finance system expansions and to develop new integrated services that can accommodate emerging alternative and renewable energy forms.

But natural gas utilities are finding it increasingly difficult to keep pace with the investment needs of the future. A basic and telling fact is that the age of Canada's natural gas delivery infrastructure has been advancing rapidly (see Chart #3)[3], particularly in those areas where investment is more discretionary, and particularly after allowed returns for Canadian natural gas utilities began to decline.



Section 1: The Public Interest, Sustainability and Canada's Natural Gas System

Increasing competition for investment in energy and energy infrastructure is a worldwide phenomenon. In a recent report, CIBC World Markets highlighted the growing Canadian and international demand for infrastructure financing and the decline in the intention of governments to provide these funds. As a result Canadian energy projects will increasingly have to compete for private investor funding.

For Canada's natural gas utilities this means they are faced with stiff competition when trying to attract more investors. Without offering investors a fair return, natural gas utilities will not be able to continue to invest in a robust, optimal, sustainable natural gas grid.

Infrastructure: the New Frontier
CIBC World Markets Report #60,
March 27 2007

"Nearly 60% of Canada's infrastructure is between 50 and 150 years old, and more than half of the systems have reached 80% of their service life.

Government spending on infrastructure as a share of total spending has declined dramatically over the past three decades, while the share of public infrastructure capital relative to overall capital stock slipped by more than a third.

The result: a ballooning infrastructure deficit, which is now rising at a rate of two billion dollars a year to reach an estimated size of more than $60 billion."

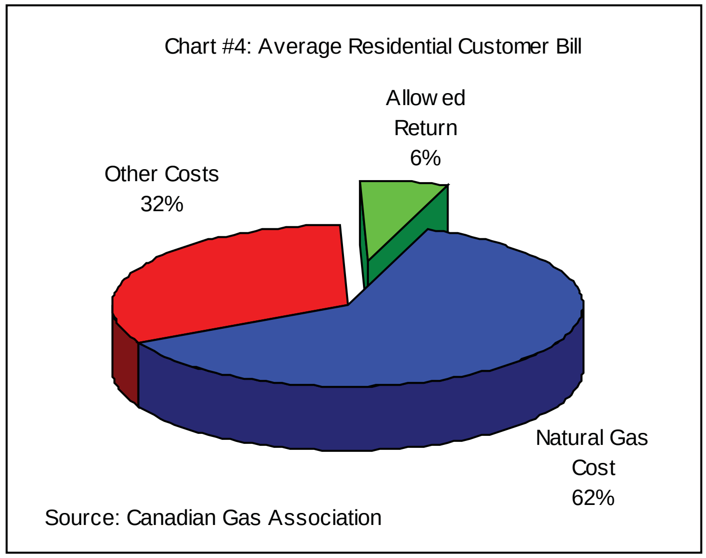
Section 2: Fair Returns and Investment in Canada's Natural Gas Utilities

A regulated natural gas utility operates in a hybrid world. Most of a utility's costs, including the cost of the natural gas supplied and the initial "hard goods" cost of the system (pipelines, buildings, computer systems etc.) required to provide safe and reliable delivery, are set by the open market. For the utility, these costs are, by and large, outside of its control and unavoidable. The regulator, acting in place of open market forces, must evaluate these costs, add in what it considers would be a "fair return" to the utility's investors, and set the appropriate rates to charge consumers.

It is this "fair return" that supports and provides the incentive for investment in the long-term strength of the natural gas grid. A "fair return" leverages the capital needed to pay for an optimal natural gas grid.

Regulation is intended to prevent any abuse of market power. However, replacing market forces with regulation eliminates the automatic incentives that competitive market pricing and investment behaviour provide in terms of promoting operational efficiency, fostering innovation, and balancing the rates customers pay against the return the utility's shareholders are allowed to earn on their investment.

To understand how allowed returns affect consumers, consider the average customer's bill. About 6% of the average residential natural gas bill in Canada is a result of the return allowed by regulators (see Chart #4). The remainder of the customer's bill reflects the pass through of costs that the utility incurs. For example the utility purchases natural gas at market prices and then passes those costs on to consumers without mark-up.



Residential Natural Gas Bills

Each customer and each utility will have a different cost breakdown based on factors such as: consumption profile of the customer, urban density of the natural gas grid, local climate and the types of assets within the natural gas utility (e.g. storage). The above chart is an average of data collected by the Canadian Gas Association.

The allowed return, though a small portion of a customer's total bill, is the primary incentive provided to the utility's investors for their investment in the development and maintenance of the natural gas grid and the energy services it provides.

The pressure that Canada's natural gas utilities face in financing their capital investments derives from the on-going decline in their allowed returns. These allowed returns termed their "return on equity" (ROE) are a primary determinant of the overall return that an investor in a regulated natural gas utility is able to earn.

A low allowed return limits the ability of the utility to respond to the various operating risks it encounters. For regulated utilities, years of low and declining returns have left them with a limited margin to absorb unexpected shocks. Events such as the loss of customers to competitors (electricity) or economic downturn, successive mild winters, or unexpected cost increases can impact the basic financial security that lenders and investors expect. Discretionary spending and investment must be set aside, contributing to a less robust natural gas grid than is in the public's interest.

Similarly declining allowed returns reduce support for longer-term investments in the natural gas grid. Declining allowed returns that degrade the utility's financial integrity can constrain access to capital financing by limiting the justification for, and ability to undertake, any investment beyond that required to ensure the safe operation of the system.

Such discretionary investments would further improve services to the public and help pave the way to energy sustainability, but are disadvantaged and often unable to garner the investment support needed to seek approval of the regulator. The result, over time, will tend to be the transfer of investment to other higher return jurisdictions, resulting in a less robust natural gas system and substantial unrealised benefits to Canadian society and the economy.

Consider the "internal" investment decision process the natural gas utility or its parent company undertakes when deciding if, and how much, to invest in the regulated utility versus other unregulated investment options:

- The parent or utility first performs a "bottom-up" analysis of all capital needs, both inside and outside the regulated utility, for a given period.

- Inside the regulated utility there are certain non-discretionary investments that must be made to fulfill safety and/or "obligation to serve" requirements, even if such investments reduce the return to the "internal" investor.

Ontario provides a recent example of how low allowed ROE levels might have prevented capital investment from going forward.

The province sought to replace coal-fired electricity generation with cleaner natural gas fired generation. This requires significant investment in natural gas storage capability to meet the needs for such a facility.

But the allowed return for such an investment was well below the returns available to the utility and its parent company from other investment opportunities. In this instance low allowed ROE failed both customers and the utility.

The solution: the Ontario Energy Board decided to by-pass the formula by allowing such investments to earn the open market rate of return.

- Remaining investment plans are then ranked by their expected rate of return. For the regulated utility this return would be the allowed return approved by the regulator.

- Remaining options with regulated returns compete directly with unregulated options for funding.

The actual amount of capital financing that the regulated utility can obtain must also be considered. These investment funds may be provided by the parent, come from internal utility cash flows, or be raised by issuing bonds or stocks.

Regulated utilities face a number of constraints on how much their annual capital budget can be funded by issuing more bonds or selling more stock. These restrictions can come as a result of financial covenants between the utility and its existing lenders or banks, from their parent company, from their regulator, and from legal requirements.

For example, a utility's ability to issue new long-term debt (bonds) is often subject to an earnings test whereby earnings must cover at least twice the cost of the existing long-term debt interest before new debt can be assumed. Since a utility's earnings are principally determined by regulated allowed returns, as allowed returns decline and earnings fall, the utility's ability to cover new debt is reduced. Eventually the utility reaches the point where it cannot finance capital investments it would otherwise have made without risking a downgrade in its debt ratings and a significant loss in value to its shareholders.

To get a full picture of the investment environment, consider the investment decision process that an "outside" investor in capital markets makes:

- "Outside" investors have no requirement to invest for "obligation to serve" or safety reasons. They are free to choose from whatever domestic and international investment options are available.

- "Outside" investors look for a return commensurate with the risk of the investment.

- When choosing between two equally risky investments a rational investor will take the one that offers the higher return.

This risk versus return comparison highlights the difficulty Canadian regulated utilities face when the allowed return they offer to investors is inadequate compared to alternative investments with similar risk profiles.

Section 2: Fair Returns and Investment in Canada's Natural Gas Utilities

The Origins and Evolution of Canada's "Fair Return" Standard

As explained, for natural gas utilities, the regulator faces the challenge of determining a fair return, instead of it being set by competitive open market forces.

In North America there is a long legal history that has guided the concepts and considerations in determining what constitutes a "fair return" for investors in a regulated utility. The legal foundations of "fair return" determination can be found in the 1929 Supreme Court of Canada Northwestern Utilities decision. [4]

In 1995 a critical evolutionary step in the rate setting and allowed return determination process in Canada was taken when the British Columbia Utilities Commission and then the NEB introduced the use of a generic formula to determine allowed returns.

With the introduction of the formulaic approach the NEB established a baseline for allowed returns in Canada. Since 1995, most provincial regulatory boards have adopted similar approaches to determine allowed returns. As a result, allowed returns for mature natural gas distribution utilities across Canada have become very uniform and have followed the same declining trend over the past decade. The elements of the formula were based on an expert, albeit subjective, opinion informed by a number of statistical studies. The starting base-year return was the combination of the following elements:

- A base return equal to the yield on long-term Government of Canada bonds, plus

- An added premium to reflect the higher risk associated with long-term stock market investments, minus

- A deduction to reflect the degree to which all utilities are considered to be less risky investments than those made in the broader stock market.

<u>Supreme Court of Canada ruling as to what defines a "fair return"</u>

In Northwestern Utilities (1929) Lamont J. of the Supreme Court of Canada held that:

The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.

Going forward, the above base-year return is then adjusted for changes in the long-term Government of Canada bond market.[5] Though some minor adjustments have been made, this basis has not been updated or significantly changed since its inception.

Though relatively straight forward in description, formula based ROE determination is far less straight forward in terms of result. In its original generic hearing (RH-2-94) the NEB heard from six expert witness panels whose recommendations on the base level of ROE ranged from 9.4 up to 14.0%. More recently, at the Alberta Energy and Utilities Board's 2004 generic cost of capital hearing, expert witnesses provided recommendations on allowed returns that ranged from 8.05 to 11.5%.

The move to a formula-based approach simplified a return setting process that had become repetitive, expensive and time-consuming. But this simplification placed increased responsibility on the policy community and regulators to ensure that "automated" allowed returns remained fair and reflected on-going changes in business financial risks and capital investment market conditions.

Natural gas utilities, governments and regulators in Canada have every reason to be concerned whether allowed returns are sufficient to generate the optimal level of investment in Canada's natural gas system. History shows that if the warning signs of under-investment in basic infrastructure go unheeded, the consequences for the society can be swift and very serious. While critical problems have not thus far arisen, we must nevertheless be mindful that such an eventuality would be uniquely harmful in a natural monopoly sector. Unlike in an open marketplace, there are no competing suppliers waiting to step in. Natural gas utilities, like electricity and water utilities, must remain functionally and financially superior to ensure customers are not left without options.

Section 3: Maintaining a Fair Return Standard

Nearly a decade after the original 1995 decision (RH-2-94) that set out the base level and current structure of the formulaic approach to returns, the NEB summarized its understanding of the "fair return standard" in its RH-2-2004 Phase II Decision. Accordingly, a fair return should meet all three of the following requirements:

I. Comparable returns
II. Financial integrity
III. Capital attraction

> ***NEB summary of key elements of the "fair return standard"***
>
> *"The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:*
>
> - *Be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard)*
> - *Enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and*
> - *Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard)*
>
> *In the Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for ... revenue requirement, result in tolls that are just and reasonable.*

The almost exclusive reliance on an adjustment mechanism that leaves significant changes in comparable returns, business financial risks and capital markets unaccounted for, discourages investment in Canada. This is putting the ability of natural gas utilities to ensure a strong and sustainable natural gas grid at risk. This lack of sufficient re-consideration of these factors is contrary to the NEB's acknowledgement "…that business risk factors influence both the capital structure as well as the rate of return on common equity."[6]

Canada's low allowed returns on equity put a sustainable natural gas grid at risk by disconnecting the incentives for delivering the energy services that the public relies upon from business and capital market realities.

Fair Returns and the Comparable Return Standard

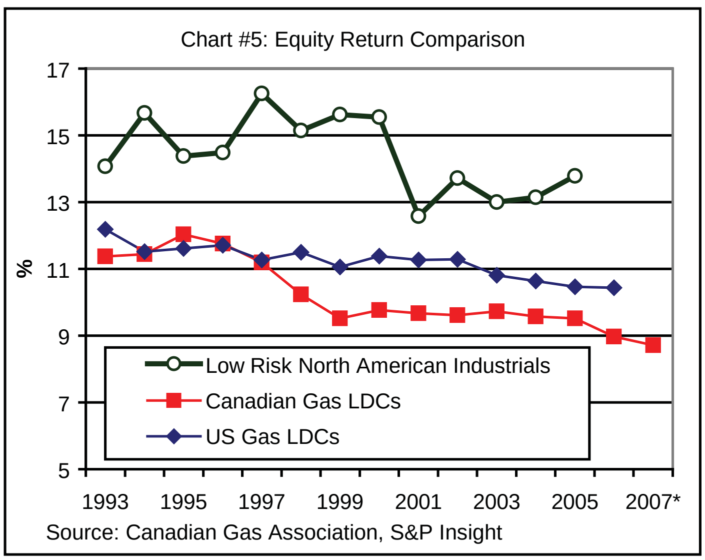
The three requirements of the fair return standard are intertwined. For example, failure to meet the comparable returns or financial integrity requirements will threaten the capital attraction requirement.

This paper focuses on the comparable returns requirement as the clearest example of where the formula is failing. To repeat the NEB summary of this requirement, a fair return should…

"Be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard)"

To discuss comparable returns, we therefore must look at the level and evolution of returns available for investments in enterprises with "like" risks and compare how the risks and returns for investments in Canada's natural gas utilities have changed since the NEB returns formula was established.

In the early 1990's, when the formula was first introduced, allowed returns in Canada matched those of natural gas utilities in the United States and were around 200 basis points[7] below low risk North American industrial enterprises[8]. But since the advent of the formula, Canadian gas utilities have seen their allowed returns drop 100 to 170 basis points below those of their US peers, and 300 to 600 basis points below the average returns for low risk North American industrials. (see Chart #5).



In the pipelines sector, which is generally subject to the same approach, this issue has already led many of the large NEB regulated pipelines, with the concurrence of their major shipping customers, to avoid using the formula for setting allowed ROE for new and existing pipeline and related facilities.

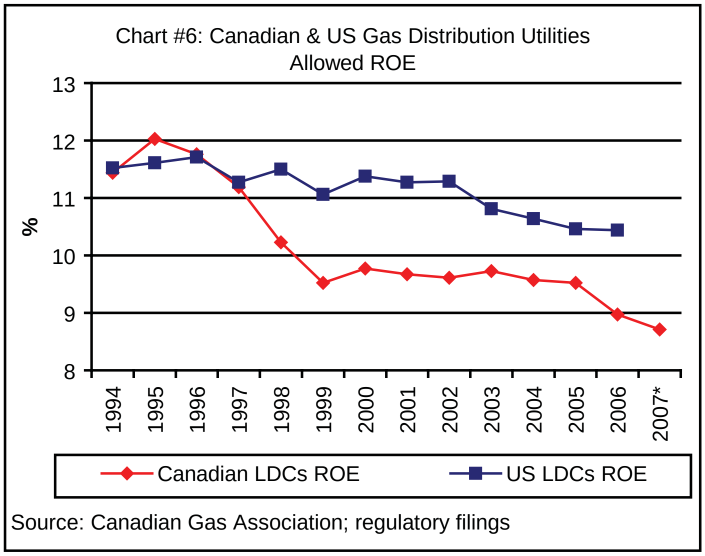
Both groups have a vested interest in the development of an optimal pipeline system with high quality service offerings. Towards this end these groups have eschewed the formula in favour of alternative arrangements for setting returns and capital structure. Similarly new pipeline projects in Canada, such as Alliance and Maritimes Northeast, have had to be allowed stable, multi-year "above formula" returns (in the 11% to 13% range) to attract the investment needed to secure their construction and financial viability.

For natural gas distribution companies, whose customer base is much more diverse and discontinuous, such "outside the formula" arrangements are harder to negotiate and generally the formula approach remains the basis provincial regulators use in setting allowed returns. While both federal and provincial regulators have generally encouraged increased use of negotiated settlements, the existence of a default, formula-based return setting mechanism linked only to long term bond rates seriously compromises the ability of the utility to negotiate an outcome which yields fair or comparable returns.

Fair Returns and a Changing Market Place

While it is clear that allowed returns have become much lower in Canada than in the U.S. (see Chart #6), it is not clear why they have diverged.

Canadian utilities are not considered to have become appreciably less or more risky than their US comparators since 1995. Assessments by the major ratings agencies (Standard & Poor's and Moody's) place Canadian gas distribution utilities within the same relative range and average risk classification as those given their American counterparts.[9]



Despite this comparability the gap between Canadian and U.S. allowed returns is not given any on-going consideration in the adjustment mechanisms used in Canada, even given the proximity and ease with which Canadian investors can, and do, access the US investment market. While Canada's regulators have continued to apply a singularly rigid formulaic approach, U.S. regulators have maintained a flexible approach that adapted to changing economic and investment market circumstances.

Since 1995 these changes in circumstance have been significant and have touched all the basic elements that the NEB initially considered in setting the initial base level for fair returns.

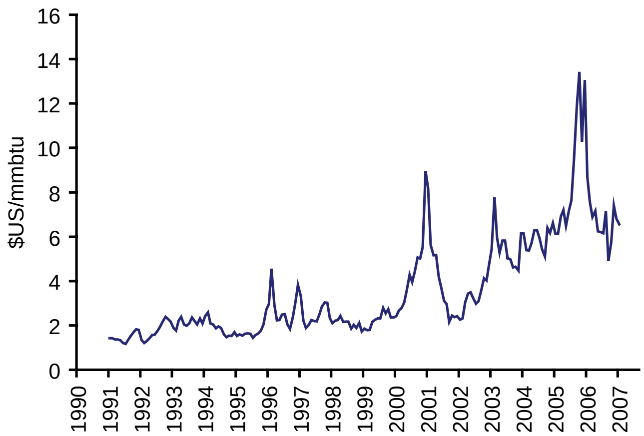
Financial markets, where natural gas utilities raise the capital to build Canada's natural gas grid, have undergone significant change. Of particular note is the liberalization of pension investment and RRSP rules to allow Canadian investors to now consider a broader range of global investments. This has increased access, for investors, to more attractive returns from comparable investments in North America and other easily accessible capital markets.

The Government of Canada bond market – the basis of the automatic adjustments for the last ten years – has been affected by a marked move from annual government deficits to annual government surpluses. This has resulted in a decline in the supply of Canadian long-bonds, an increase in their price and a decline in their return. This, in turn, has led to an automatic decline in allowed returns for Canadian natural gas utilities that is disconnected entirely from their risk profile. This situation is highlighted in the 2007-2008 Debt Management Strategy Report by the Department of Finance which states;

> *"A continuing challenge for the Government's debt strategy in recent years has been to maintain sufficient issuance of Government of Canada bonds to support a liquid and efficient market. The challenge arises from the combination of declining federal borrowing needs and the decision to reduce the fixed-rate share of the debt, which has reduced the bond stock in favour of treasury bills. Over the past 10 years, net annual bond issuance has fallen by 60 per cent, from a peak of $56 billion in 1996–97 to $23.5 billion in 2006–07. Gross annual bond issuance has fallen only 40 per cent to $33.5 billion in 2006–07 due to the use of buybacks."*

Business financial risks of natural gas utilities have increased, particularly due to changing energy markets, environmental imperatives including improving energy efficiency[10], and increased competition from other energy forms. For example, since 1995 market prices for natural gas have become significantly higher and more volatile (see Chart #7).

Chart #7: Natural Gas Commodity Price Volatility



Source: US Federal Reserve, St. Louis

With higher prices, other risks such as weather and average use per customer, are magnified because a given unexpected change in natural gas volumes – multiplied by the cost of purchasing the natural gas commodity – now has a much larger impact on a utility's finances. Higher natural gas prices have also increased pressure for consumers to switch to electricity whose prices in most provinces are held artificially low and stable by government energy policy.

Section 4: Restoring Fair Returns

Shareholders of Canadian gas utilities are not receiving allowed returns comparable to those received by shareholders of US gas utilities or low risk non-regulated enterprises. This stands in direct conflict with the responsibility of Canadian regulators to provide comparable, fair returns. Canadian gas utilities are finding it increasingly difficult to finance the infrastructure that best serves the public interest because their returns do not reflect the changing realities of the business and financial markets in which they operate. As a result, Canadian utilities are inhibited from offering a robust, optimal system that would provide the highest quality of service today, and would be properly oriented towards a sustainable energy future.

Canadian regulators decided to move to a formula-based generic returns process largely to improve regulatory efficiency — narrowly defined — in determining companies' allowed rates of return. In this regard, the formula-approach has been an improvement: the time required for rate cases has been reduced as have the direct costs of regulation. However, while useful for providing a mechanistic starting point for what a "fair return" may have been, the automation of the allowed return process increased the responsibility of the policy community and regulators to ensure that allowed returns remain fair and appropriately reflect the significant changes seen in their foundational elements such as comparable earnings, business operating risks and competition in capital markets.

The formula is not protecting the public interest in a robust and sustainable natural gas delivery system by failing to provide utility investors with a fair return on their investment. Canadian policy makers and utility regulators should give early and serious consideration to realigning stakeholder objectives and related incentives. In particular it is necessary to:

i. Recognize the necessity of a long-term, low-cost optimal natural gas delivery infrastructure, oriented towards future energy sustainability, rather than the minimal, short-term least cost system that risks emerging from a prolonged period of depressed allowed returns.

ii. Take immediate steps to eliminate the formula-induced deficit between allowed returns for natural gas utilities in Canada and those of other comparable North American natural gas utilities.

iii. Seek to provide appropriate capital market signals to investors by having allowed returns formulas include direct consideration of comparable natural gas utility and low risk enterprise returns in North America.

iv. Convene a national review of the generic formula approach, its ability to meet the requirements of the fair return standard, and respond to the significant changes seen in the economy, government bond market, capital markets and stock markets since 1995.

End Notes

[1] One hundred (100) basis points equal one percentage point.

[2] For a complete discussion of GHG abatement see "Global Mapping of Greenhouse Gas Abatement Opportunities up to 2030, January 2007, Vattenfall AB, Europe.

[3] For a complete discussion of the capital investment history and investment needs of Canadian natural gas utilities please refer to "The Canadian Gas Distribution Industry: Investment and its Adequacy", Informetrica Ltd, unpublished

[4] The Northwestern decision in Canada builds on previous US decisions that include the 1898 Smyth vs Ames and the 1923 Bluefield Water Works utility decision and was followed in the 1944 Hope Natural Gas decision. A summary of these key historical legal precedents is given in Appendix A.

[5] The NEB uses an automatic adjustment mechanism that in general raises (or lowers) the allowed return by a fraction (75%) of change in the long term government bond market.

[6] Amending Order AO-1-RH-2-94 (Filing Requirements for the RH-2-94 Hearing) May 30, 1994, page 5.

[7] One hundred (100) basis points equals one percentage point.

[8] Based on ratings by the major North American bond ratings agencies.

[9] "North American Natural Gas Transmission & Distribution", October 2006, Moody's Investors Service Industry Outlook, Global Credit Research.

[10] For a complete review of how efficient improvements have led to declining average use of natural gas in Canada please refer to "Declining Average Use of Natural Gas: Issues and Options, J Simon, IndEco Strategic Consulting, December 2006.

Appendix: Key Legal Precedents for Fair Return Definition

Smyth versus Ames – 1898 (a group of railroads versus Nebraska)

the corporation may not be required to use its property for the benefit of the public without receiving just compensation for the services rendered by it.

we hold however, that the basis of all calculations as to the reasonableness of rates…must be the fair value of the property being used by it for the convenience of the public.

Bluefield Water Works – 1923 (a water utility versus West Virgina)

a public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.

the return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties

Northwestern Utilities – 1929 (a gas company versus Edmonton)

by a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.

Hope Natural Gas – 1944

the rate-making process under the Act, i.e., the fixing of "just and reasonable" rates, involves a balancing of investor and the consumer interests.

thus we stated in the Natural gas Pipeline Co. case that "regulation does not insure that the business shall produce net revenues."

but such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated.

From the investor point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. …

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

Allowed Return on Equity in Canada and the United States

An Economic, Financial and Institutional Analysis

National Economic Research Associates, Inc.
Kenneth Gordon, Ph.D
Jeff D. Makholm, Ph.D

MMC Marsh & McLennan Companies

February 2008

This study was commissioned by the Canadian Gas Association.

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I. INTRODUCTION[1]

Canada and the United States have almost hundred-year histories of regulating investor-owned utilities. This shared experience is different from almost all of the rest of the world, where the appearance of investor-owned (i.e., private) utilities came only with the privatization wave of the late 20th century. The regulatory laws, mechanisms and institutions in those other countries are new—and in many cases untested. But longstanding regulatory institutions in Canada and the US have for decades been helping to provide safe and adequate services to the public at reasonable prices while ensuring that the companies involved remain "going concerns" with sufficient credit worthiness to attract the capital needed to maintain and expand their facilities.

Over the past decade, however, a significant difference has appeared in the regulatory practices between Canada and the US. In an effort to improve regulatory efficiency, Canadian regulators—first in British Columbia, then more widely—moved away from the case-by-case approach to determining the fair return on equity (ROE) for utility rate making purposes. Canadian regulators adopted generic, formula-based approaches to deriving the admittedly elusive fair ROE. US regulators in the 1980s and 1990s made two tries at generic, formula-based approaches to setting the ROE (one at the federal level and one in the State of New York), but, in the end, did not abandon their longstanding, case-by-case methods that rested on two existing and long-accepted financial theories.

The apparent efficiency of bypassing case-by-case evidentiary proceedings with a generic formula may have foretold a new and more efficient method of deriving regulated rates generally—except for one thing. The current Canadian generic ROE formula appears to have created a persistent divergence between allowed gas utility returns in Canada and the US. Since 1998, ROEs used to make regulated tariffs have been, on average, 100 to 150 basis points lower than in the US. That is, in dozens of evidentiary proceedings since 1998, US regulators have allowed their companies to set tariffs reflecting ROEs that were on average substantially higher than for their Canadian formula-driven ROE counterparts.

The purpose of this report is to analyze the root causes of this disparity between Canadian and US ROEs that has apparently been propelled—either directly or indirectly—by the Canadian ROE adjustment formula. Since the "appropriate" level of ROE is driven by the risk/return requirements of those utility investor-owners, the obvious question is whether Canadian utilities face sufficiently less risk than their US counterparts. Conversely, we investigate whether the difference in allowed returns for ratemaking is merely a symptom of a structurally inflexible formula rather than an indicator of underlying risk differences. If it is the latter, then Canadian regulators have indeed streamlined rate cases for the better. If the former, then perhaps the formula has had unintended consequences and is in need of updating better to reflect the market's judgment on the cost of equity of regulated Canadian utilities.

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[1] This report was written by NERA's Kenneth Gordon, Special Consultant and former Chairman of the Department of Public Utilities Massachusetts and the Public Utility Commission in Maine and Jeff D. Makholm, Senior Vice President. They were supported by Ryan Knight at NERA.

It is important to state at the outset how we approach examining this divergence   We cannot automatically presume that the burden falls on Canadian regulators to justify the persistently lower average ROEs than those granted by their US counterparts. Nevertheless, it is the group of Canadian regulators that changed course in the last decade, led by those regulators using the generic formula for streamlined regulatory procedures. Those regulators in the US who failed to find a suitable way to streamline their ROE procedures continued on the former path common to both Canadian and the US regulation—to examine anew, in every tariff case, expert evidence on ROE for the company in question for the relevant period of time. We do not believe that either Canadian or US regulators would consider the results of those case-by-case evidentiary procedures to be biased on a large scale. They are perhaps expensive, time consuming or overwrought—but not biased. Therefore, it is natural—and again to us justifiable—to subject the new Canadian generic formula to the test of bias. If we find that Canadian and US utilities face comparable operating environments and risk to investors, then it is natural to question the efficacy of the new Canadian formula approach to the ROE, not the traditional path US regulators still hold. It is therefore not prejudgment that prompts us to examine underlying justifications for the new and lower Canadian ROEs, but practicality. We do not question whether US regulators (or Canadian regulators up to the adoption of the new formula) were incapable of deriving "just and reasonable" tariffs. What we do question is whether, based on underlying risk factors, the new Canadian generic ROE formula can do likewise.

Canadian regulators have acknowledged in rate cases that a disparity exists between Canadian and US allowed ROEs, but have not concluded whether or not the disparity warrants action.[2] For example, the regulator in Quebec, the Regie de l'Energie, stated in 2007, "[i]n the Regie's view, even though rates of return allowed in the United States are clearly higher on average than those allowed in Canada, the evidence does not make it possible to conclude that there is any prejudice to or unfair treatment of the distributor.... The evidence does not make it possible to compare the overall differences that may exist in the institutional, economic and financial contexts of the two countries and their impact on the opportunities they provide for investors." [3]

Unfortunately, nothing surrounding the required ROE for the purpose of making regulated tariffs is an easy discussion. Unlike the other elements of tariff setting (operating costs, maintenance costs, administrative expenses or the interest rates on utility bonds) the ROE is not directly observable. The required ROE is a function of investor *expectations*. Those expectations remain complex functions of how investors believe that price regulation, along with the utility's other circumstances, will work to allow them a return on the capital that they devote to serving the public. Given the complexity associated with discussion of the fair ROE, this report will examine the root of the post-1998 differences in permitted ROEs. Those differences stem either from corresponding differences in risk in Canada versus the US or from more banal causes relating to the operation of the generic ROE formula itself vis-à-vis investors' genuine risk-driven expectations.

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[2] *See*: Ontario Energy Board (OEB) *A Review of the Board's Guidelines for Establishing Return on Equity* RP-2002-0158 (2004) ¶ 122. *See* also: Alberta Energy Board (EUB) *Generic Cost of Capital* Decision 2004-052 (2004) pgs 25-27.

[3] Regie de l'Energie, *Decision: Application to Modify the Tariffs of Gaz Metro Ltd*. D-2007-116 (2007) §4.1.10.

The report concludes that the regulatory environments in Canada and the US are highly similar and directly comparable. Since the world's first utility commission regulatory statute was written in the US in 1907 in Wisconsin, that general form has been widely copied in all states and provinces in Canada and the US.[4] These two national jurisdictions thus share a common heritage that is quite different, for example, from the newly-privatized regulatory jurisdictions in the rest of the world. Those jurisdictions overseas regulate their investor-owned utilities on an institutional basis quite different than in Canada and the US—two countries that share the longest, largest and most unencumbered trade border in the world. It is thus a fair question to compare and contrast Canadian and US utilities with each other to examine how their regulators deal with them and, in particular, derive the ROEs used to set their regulated tariffs.

Section II contains our Executive Summary. In **Section III**, we examine the evident divergence between allowed returns in Canada and the US that propels this study. In **Section IV**, we compare the methods used for setting base ROEs in Canada to the case-by-case methods still used by US utility regulators, despite two highly visible attempts to create generic formulas there. In **Section V**, we examine the sources of risk for regulated utilities and any apparent differences between investor-owned utilities in Canada and the US that might, in principle, explain the wedge in ROEs that has appeared since 1998.

[4] That statute was drafted by John R. Commons, a professor of economics at the University of Wisconsin and 10 years later the President of the American Economic Association.

II. EXECUTIVE SUMMARY

In the introduction to this report, we stated that we do not automatically presume that the burden falls on Canadian regulators to justify the persistently lower ROEs allowed relative to their US counterparts. First, those numbers may not fairly gauge the treatment of Canadian gas distributors on the part of regulators. Second, those ROEs may combine with other aspects of Canadian financial markets or regulatory procedures that do not generalize to the US. Third, the relative ROEs may reflect business, regulatory, or financial risk differences for Canadian gas distributors versus their US counterparts.

Taking these elements into account, however, it is our opinion that the generic Canadian formula itself should be the subject of scrutiny. The formula works like an "autopilot" for setting new Canadian ROEs that uses long bonds as the only contemporary gauge of financial markets—instead of directly targeting equity costs. If the new autopilot has been setting a different course than the case-by-case "human" pilots that previously characterized Canadian ROE, and still characterize US ROE setting, then the autopilot should bear the burden of showing that it is not biased. We cannot conclude going in that the group of independent regulators setting their own ROEs on a case-by-case basis are the ones to be exhibiting a bias.

Figure 1 in our report, showing a marked split in the allowed ROEs in Canada and the US, demands the examination of three issues regarding the meaning and comparability of the relative ROEs before the question of whether the Canadian formula has exhibited a bias in recent years can be addressed:

- We explain that under both Canadian and US regulatory methods, the ROE is the measure of cost of capital that enters the formula to make "just and reasonable" rates. It is the measure of compensation allowed for the capital that investors devote to the service of the public *at the time rates are set*. What happens afterward—in other words, what the utilities actually achieve in profitability—is a different matter. The actual returns reflect many things including management effectiveness, sales growth, the weather, macroeconomic considerations, changes in capital costs, etc. But regulatory treatment of investor-owners is tightly bound to the ROE. We conclude that allowed ROE is the proper metric for comparison.

- We find that the regulatory institutions and customs for setting regulated prices for investor-owned Canadian and US utilities are very alike. That is, in accounting, administrative procedures, regulatory legislation, and basic constitutional protections of private property, little or nothing separates the average Canadian from the average US regulatory jurisdictions, unlike newly-privatized utilities in new regulatory jurisdictions overseas, where regulatory institutions are young (and largely untested),. There are of course differences in regulatory treatment from province to province and from state to state. But we find generally that there is no persistent difference in regulatory legislation or rule making between Canada and the

US.[5] As such, the cost of equity capital is comparable between the two countries as long as the risk of gas distributors is the same or similar on both sides of the border.

- We examine the definition of risk to investors of placing their capital at the use of the public, for which the ROE provides compensatory payment. We look at how those risks could be different in Canada versus the US. What we find is that the basic sources of risk—regulatory, business and financial—are comparable with respect to both jurisdictions. Objective and disinterested analyses of the relative risks between Canadian and US utilities are rare, but what we have found points to no smaller risks in Canada. As such, we conclude that there is no objective evidence showing that business or regulatory risks are sufficiently lower in Canada to account for the divergences shown in **Figure 1**.

With this analysis, our conclusion is inescapable. The Canadian ROEs produced by the generic Canadian ROE formula are biased downward. The formula has, since its inception, ridden on autopilot the declining Canadian long-bond interest rates (the cost of a kind of debt) with no independent check on the cost of equity. The generic Canadian formula might not always be biased, and indeed in an era of stable interest rates and equity markets it may have held a true course for many years. But is has been overtaxed by the relatively unprecedented decline in interest rates since the late 1990s. The uncorrected, un-calibrated formula—not risk differences or inherent Canadian regulatory differences—has driven the divergence between observed Canadian and US ROEs.

The manifest remedies are either to return to "human" pilots (representing case-by-case ROE determinations) or re-calibrate the Canadian generic formula by re-examining the current relationship between the contemporaneous cost of debt and gas utility equity. Given the similarity in the jurisdictions, the institutions of regulation and capital markets, it would be useful in our opinion to employ both Canadian and US gas utility equities in such an analysis, along with both of the main cost of equity models (DCF and CAPM). Without a new calibration, it is likely that as long as the interest rates in Canada and the US remain low, the generic ROE formula will continue to fly off course—essentially treating Canadian utility investors unfairly and slowly taxing their financial health in this era of low interest rates.

[5] If one threw all 63 federal and provincial/state regulatory statutes (13 for Canada, 51 from the US) into one pile with all the names blacked out, we would challenge anyone to sort them into a Canadian or US pile based on their content alone.

III. AN EVIDENT DISPARITY IN CANADIAN AND US ALLOWED RETURNS

This report is propelled by the need to examine the persistent gap between the allowed returns on equity for ratemaking purposes between Canadian and US regulators.[6] This section examines what the divergence is and where it comes from. It examines whether the ROE figures in Canada and the US are both a reasonable and comparable metric for determining effective regulatory control over profitability in both countries, and also describes how the Canadian ROE formula works.

There are two key questions. First, does the divergence mean anything? Is the ROE (as opposed to earned returns) the right metric for comparison? Second, are the economies comparable enough (given differences in taxes, etc.—everything but regulatory risk) to permit ROE comparisons.

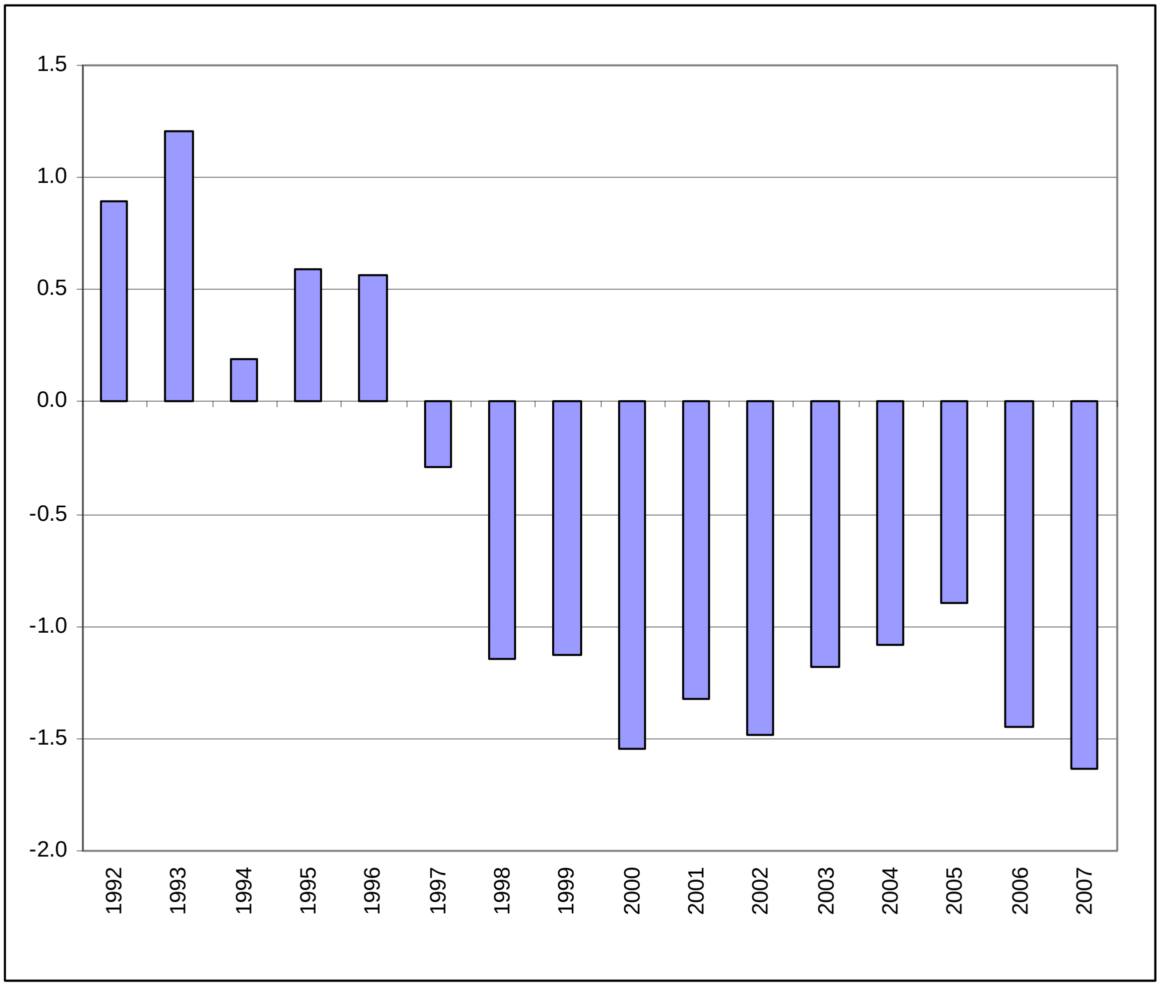
A. The Divergence between Canadian and US Allowed Returns for Ratemaking

Figure 1 shows that Canadian allowed returns were, at one time, higher than those allowed in the US, but that this changed during 1997. Since then, Canadian allowed returns have been markedly lower than those in the US.

Figure 1 was compiled using data submitted by members of the Canadian Gas Association (CGA) for Canada and data gathered from Regulatory Research Associates for the US. The CGA submitted data for 8 Canadian LDCs, although data were not available for every LDC for every year. The number of rate case decisions for US LDCs for which Regulatory Research Associates data were available varies from 10 in 1999 to 42 in 1993. The data used to construct Figure 1 is presented in **Table 1** below.

[6] It is important to keep in mind that "allowed returns" (i.e., ROE) means the rate of return equity, permitted in a rate case proceeding, to form a component of regulated prices. It does not refer to an attempt by regulators to control the return on capital actually earned by utilities once those rates are set. Ratemaking in Canadian and US jurisdictions is generally a *prospective* exercise.

Figure 1: Allowed Return Average Differential (Canada-US) for Gas Distribution Utilities, 1992-2007



Source: Canadian Gas Association, Regulatory Research Associates.

- **Figure 1** was generated by subtracting the average allowed US ROE from the average allowed Canadian ROE for each year. This differential for Canada ranges from 121 basis points above US ROEs in 1993 to 164 basis points below in 2007. Starting in 1997, the differential has been consistently negative; indicating that, over the past decade, average allowed US ROEs are higher on average than those in Canada. These average allowed ROEs for both countries are presented on **Table** 1.

Table 1: Canada-US Average Allowed Return Differential, 1992-2007

	Canada	US	Difference
1992	12.88	11.98	0.89
1993	12.58	11.37	1.21
1994	11.44	11.24	0.19
1995	12.03	11.44	0.59
1996	11.68	11.12	0.56
1997	11.01	11.31	-0.29
1998	10.38	11.52	-1.15
1999	9.52	10.64	-1.12
2000	9.80	11.35	-1.55
2001	9.64	10.96	-1.32
2002	9.61	11.10	-1.48
2003	9.79	10.97	-1.18
2004	9.55	10.63	-1.08
2005	9.52	10.41	-0.89
2006	8.99	10.43	-1.45
2007	8.71	10.35	-1.64

By the simple metric of average ROEs in Canada and the US, a clear disparity has emerged. This disparity was the subject of a recent report by Concentric Energy Advisors, which examined the disparity between Ontario LDCs and US LDCs in particular. The Concentric Report concludes that Canadian ROEs were more sensitive to the drop in bond yields over this period than were US ROEs.[7] Further, the Concentric Report suggests that this sensitivity arose through the adoption of an automatic adjustment mechanism that explicitly ties Canadian ROEs to long-bond prices.[8]

B. Is Allowed ROE the Proper Metrics for the Comparison of the Treatment of Utilities by their Regulators?

A threshold question is whether the figures in Table 1 mean anything in terms of assessing regulatory treatment in Canada versus the US. That is, given the unique economic and financial contexts of each country, are ROEs structurally different such that an allowed return in the Canada does not mean the same thing as an allowed return in the US?

Three issues arise in answering this question. First, is the ROE the proper metric, as opposed to the return that the utilities in question have actually achieved during the period of time the rates were in effect? It is a question that arises often in comparison of ROEs. Second, does capital flow freely between countries? If capital does not flow between countries, allowed returns are

7 Concentric Energy Advisors, "A Comparative Analysis of Return on Equity of Natural Gas Utilities," prepared for Ontario Energy Board (2007). p. 2.

8 *Id.*, p. 56.

likely to not be comparable as capital costs would reflect strictly national macroeconomic considerations. Third, given the distinct tax and financial environments, such as differences in country-specific interest rates, are allowed returns similar indicators in both Canada and the US? This section examines these issues in turn.

1. Allowed ROEs versus Achieved Returns

Is the allowed ROE the proper metric, or are the returns that the utilities in question have actually achieved during the period of time the rates were in effect the relevant indicator? We readily conclude that the answer is yes: allowed ROEs are the proper metric. Both in Canada and the US, the general manner of regulatory control is for regulators to set *reasonable rates* and then allow utilities to do the best they can to make a business and earn a reasonable return against those rates. That is to say, utilities in Canada and the US are not cost-plus businesses that can appeal to cover costs after the fact. Utilities are not confined to any particular return. There are admittedly exceptions (which we consider idiosyncrasies) to this general statement—but the character of ratemaking control in both countries is prospective.

For over a century, both in Canada and the US, the pull between private enterprise and the public welfare has been settled just this way: regulators deem the return to be considered “just and reasonable” and the private utility subsequently does its best to profit—until such time as the regulator or the utility request that the question of the forward-looking just and reasonable rates should be adjudicated again.

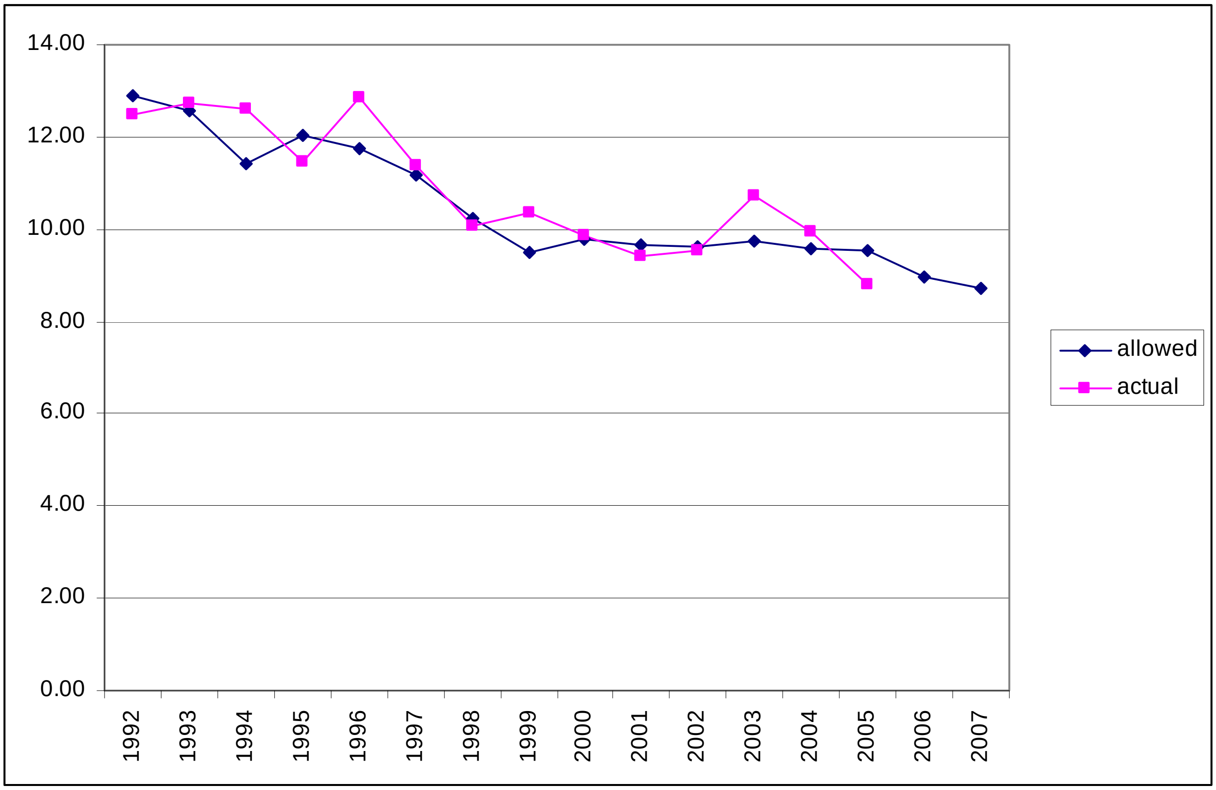
It follows that if the ratemaking mechanisms defined by regulatory legislation and rulemaking (*i.e.*, how costs are added together and then divided by measured sales to form the rate) are the same in Canada and the US, then the allowed ROEs are directly comparable. After the fact, some utilities may profit more than others (*e.g.*, those in fast-growing service territories versus slow-growing ones).[9] Or there may be some times when it is easier than others for utilities to profit (*i.e.*, when capital costs are generally falling rather than rising against a fixed set of just and reasonable rates). But with the commonality of ratemaking mechanisms in Canada and the US, the role of the allowed ROE is the same. Hence, its comparability across jurisdictions is proper.

If ratemaking procedures and operating conditions are comparable in Canada and the US, there would be no reason to expect utilities in either country would regularly earn more than the allowed ROE. **Figure 2** shows that, as we would expect, given our review of the mechanisms of rate regulation in Canada, earned returns have been both above and below allowed returns in

[9] There is a comparison between returns for Canadian and US regulated pipelines, offered in NEB RH-2-2004 by CAPP (the Canadian Associate of Petroleum Producers) that might seem to suggest a persistent success in achieved returns for Canadian companies versus their US counterparts (although we have not looked closely into the sources or particular reasons for those results reported by CAPP). We note, however, that these are returns obtained by federally-regulated interstate pipeline companies, not local gas utilities. Those pipeline companies do not have the public service obligations or stable customer base of distribution companies, and they are not informative to the comparison of the Canadian versus US *utility* ROEs. *See:* NEB, *Reasons for Decision* RH-2-2004 Phase II (2005), Figure 5-1.

Canada since the inception of the formula. In our experience, this pattern of allowed versus actual ROEs, reflecting occasional average divergences, is characteristic of utilities in the US as well.

Figure 2: Allowed versus Earned Returns For Gas Distributors in Canada, 1992-2007



Source: Canadian Gas Association

We show **Figure 2** merely as a way of dealing again with the statement that earned returns—an *ex post* measure of utility performance against a fixed set of "just and reasonable rates"—is not exceptional in Canada. There is nothing, to us, in **Figure 2** that removes the reasonable use of **Figure 1** as a reason to question whether Canadian ROE methods lately have been causing a divergence in the fair return between Canada and the US.

2. Capital Flows

There is no doubt that Canada and the US can experience unique macroeconomic conditions (interest rates, inflation, GDP growth, etc.). That said, Canada and the US share the longest, largest and most open trade border in the world. There has not been a shot fired in anger across this border since 1812. Canada-US trade is open, with few import or export taxes or tariffs.

Energy trade in North America is governed by the North American Free Trade Agreement (NAFTA), the Canada-US Free Trade Agreement (FTA), and the General Agreement on Tariffs and Trade (GATT). Among other things, NAFTA has "provided the building block for the emergence of a cooperative North American market for energy goods."[10]

Today, there are:

- 35 cross-border natural gas pipelines between the US, Canada, and Mexico.
- 22 cross-border oil and petroleum product pipelines.
- 51 cross-border electric transmission lines.

These facilities physically bind Canada and the US together.[11] This physical integration is matched by capital market integration as well. Since deregulation of the wellhead price of natural gas (1985 in Canada, 1981 in US), trade in this "increasingly significant sector" would be based on "internationally-recognized, non-discriminatory market access principles."[12] With competitive markets for the gas commodity and for transport capacity, shippers can negotiate for gas supplies and pipeline space on transmission systems in both Canada and the US, searching for the most economical mix of commodity and transport costs. The situation between Canada and the US is remarkable—unlike many parts of the world, where pipelines are not built if it means passing through other countries.

There does appear to be a preference for domestic investment, especially by pension funds and other "trustee investments," which could result in segmented capital markets. However, many Canadian firms are cross-listed on US exchanges—including Enbridge. As identified by the Concentric report, US investors do play a significant, albeit less prominent, role in the capitalization of Canadian utilities.[13] To the extent that the trustee investments in Canadian utilities represent a structural barrier to investing outside the country, then the cross-border equity investments from the US are a marginal source of funds.[14] Furthermore, some Canadian utilities and their parent companies engage in business in the US and abroad, indicating that utility companies are not regionalized.

One test of the comparability of allowed utility returns is the cost of capital for non-utility firms in Canada and the US. It may be that there are structural differences in the cost of capital

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[10] *See:* North American Energy Working Group, "North American Natural Gas Vision," Experts Group on Natural Gas Trade and Interconnections, January 2005: http://www2.nrcan.gc.ca/es/es/naewg/NANaturalGasVision_e.cfm (Accessed on October 28, 2007).

[11] *Id.*, p. 34.

[12] *Id.*, p. 10.

[13] Concentric, s*upra* note 4 p. 50.

[14] Under the efficient markets hypothesis, the marginal investor sets the price for a security. To the extent that this hypothesis holds, it may be that US investors are leading the valuation of Canadian firms. *See:* Ibbotson, R.G. and G.P. Brinson, *Global Investing: The Professional's Guide to the World Capital Markets*, McGraw-Hill: New York (1993), p. 37-41.

between Canada and the US that would result in a categorically lower cost of capital for Canadian firms, reflecting a lower opportunity cost of investment for Canadian utilities.

In an attempt to address this question, a 2007 study by researchers at the Bank of Canada estimated a cost of capital 30-50 basis points *higher* for Canadian firms than US firms, all else equal. The study estimated cost of capital based on a forward-looking, discounted cash flow (DCF) analysis of Canadian and US firms from 1988 to 2006.[15] This study takes into account forward-looking investor expectations, and is evidence that the cost of capital does not appear to be categorically lower in Canada.

3. Tax Differences

Differences in tax laws have been proposed in some previous discussions about the differences in recent Canadian and US allowed returns as a potentially confounding factor in Canada-US comparisons. Tax rates facing Canadian and US investors are indeed different, both for domestic and cross-border investments. However, it is the practice of Canadian and US regulators to set allowed ROEs on a pre-tax basis, permitting income taxes for the utility, as such, to enter the ratemaking formula as a pass through expense in permitted rates.[16] In other words, income taxes are treated in both jurisdictions as a measurable expense when grossing up the pre-income-tax ROE to calculate a post-income-tax figure for use in setting consumers charges. Therefore, as the income tax treatment is similar, if the institutional, financial and economic risk environments are comparable, ROEs are comparable as well, regardless of differences in taxation.

4. Macroeconomic Interest Rates

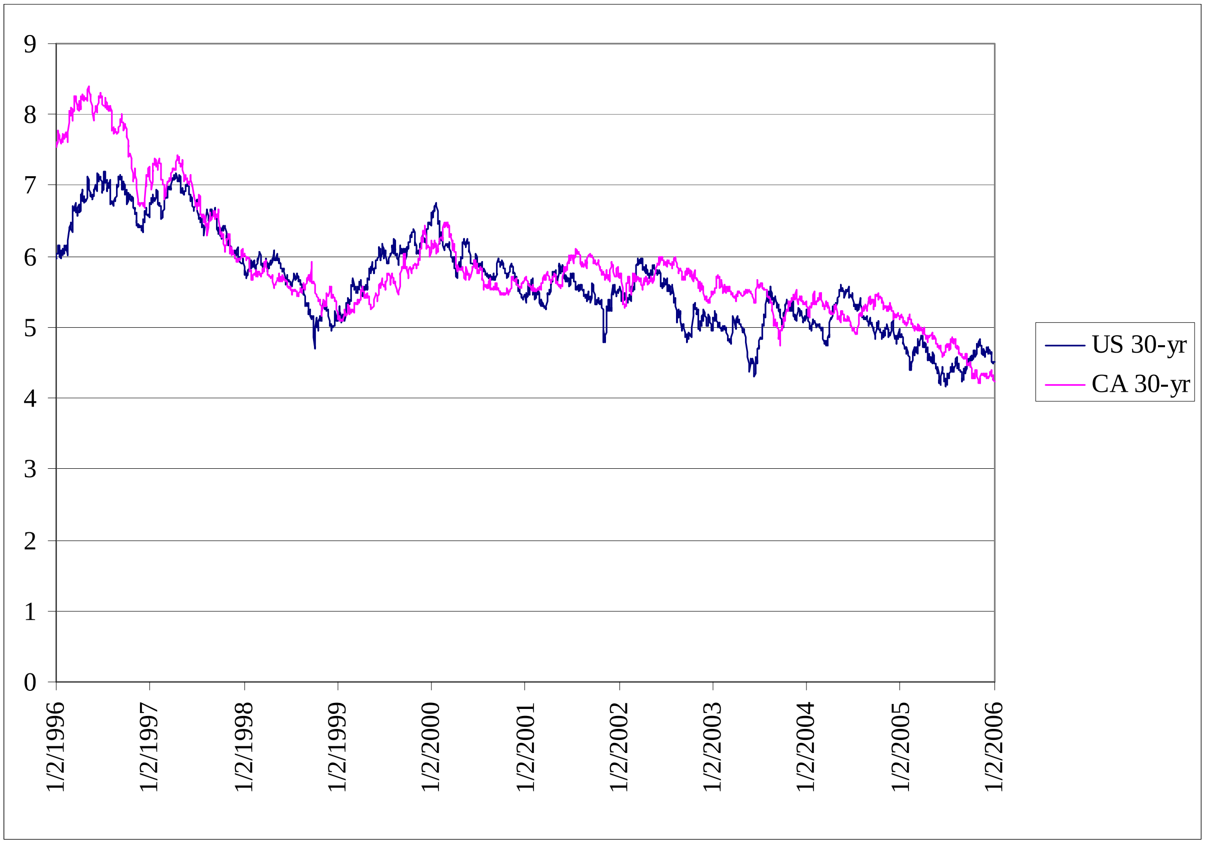
If interest rates forecasts are substantially lower in Canada, the apparent disparity in allowed returns may simply be a byproduct of lower underlying capital cost rates, and there may be no difference in the relevant fair ROE awarded by Canadian and US regulators.

As **Figure 3** shows, interest rates have been in rough parity since the beginning of the divergence, and US long-bond yields were even below Canada's for much of the time. This would indicate that macroeconomic interest rates are not driving the divergence since 1998 (although they may account for some of the positive divergence before that time), given that US interest rates have been both above and below Canada's rates during the period of interest.

[15] Witmer, J. and Zorn, L. "Estimating and Comparing the Implied Cost of Equity for Canadian and U.S. Firms" Bank of Canada Working Paper 2007-48 (2007). Available at: http://www.bank-banque-canada.ca/en/res/wp/2007/wp07-48.pdf (Accessed on 11/15/07).

[16] The income taxes on dividends or capital gains for individual investors are not a subject of concern to Canadian or US regulators—only the income taxes that form a part of compensatory rates for the utility.

Figure 3: Long-Term Bond Yields in Canada and the United States (1996-2006)



Source: US Treasury Department and Bloomberg

C. The Source and Form of the New Canadian ROE Methods

Beginning in 1994, Canadian regulators—first some, then others—have adopted automatic adjustment mechanisms for setting the ROE in utility rates based on a fixed spread with observed movements in Canadian interest rates on long bonds. In these jurisdictions, the ROE is automatically adjusted annually based on movements in long-term bond forecasts.

The approach used by the NEB, Ontario, Quebec and Alberta is to establish a "benchmark" ROE that is applied to all utilities, with individual business risks taken into account when the capital structure is "deemed."[17] The generic ROE is then adjusted annually as follows:

[17] Capital structures are "deemed" in Canada based on relative business risk. An LDC with more business risk will be deemed a higher equity ratio in its capital structure to raise the overall weighted average cost of capital. This contrasts with the US, where LDCs are predominantly allowed to choose their capital structure within a band of reasonableness.]

1. The forecast yields on 3 and 12 month out 10-year Canadian bonds are obtained from the most recent forecast by Consensus Economics.

2. These two forecasts are then averaged.

3. To get an estimate for a 30-year forecast, the result is adjusted to reflect the actual spread between 10-year and 30-year bonds in the previous month as reported in *The Financial Post*.

4. This estimated 30-year forecast is subtracted from the previous years' forecast.

5. The difference is multiplied by 0.75.

6. The new ROE is previous years' ROE plus (minus) the result.

Some provinces may use a slightly different adjustment, but the process is largely similar. The ROE adjustment is shown in Equation 1.

$$ROE_t = ROE_{t-1} + .75(Forecast_t - Forecast_{t-1}) \qquad \textbf{(1)}$$

Using this formula, the following rates would result from a benchmark ROE of 12 percent based on interest rates of 8 percent if interest rates were to fall.

Table 2: Hypothetical Formula-Based ROEs

Bond forecast	Allowed ROE
8.00	12.00
7.00	11.25
6.00	10.50
5.00	9.75
4.00	9.00
3.00	8.25

The formula approach was first introduced in British Columbia in 1994 before being adopted by Manitoba and the NEB in 1995. Ontario adopted the NEB approach for 1997, and was followed by Quebec in 1999. Finally, Alberta adopted formula adjustments in 2004.

Table 3: Major Jurisdictions Implementing Formula-Based ROEs

Regulator	Jurisdiction	Case ID	Year
British Columbia Utility Commission (BCUC)	British Columbia	Decision in the Matter of Return on Common Equity, June 10, 1994	1994
National Energy Board (NEB)	Federal	Reasons for Decision re: RH2-94 Cost of Capital, March 1995	1995
Public Utilities Board of Manitoba (PUBM)	Manitoba	PUB Order 49/95	1995
Ontario Energy Board (OEB)	Ontario	Draft Guidelines on a Forumla-Based Retun on Common Equity for Regulated Companies	1997
Regie de l'Energie	Quebec	D-99-11	1999
Alberta Energy Utilities Board (EUB)	Alberta	2004-052	2004

The 0.75 adjustment factor arose out of the 1995 NEB formula decision. The formula is based on the historical observation that allowed returns tend to move in the same direction as long-term bond yields. There was a desire to protect utility customers from high bond yields and shareholders from low bond yields, so the NEB decided to weight the ROE movement by 0.75 times the change in bond prices. Previously, Manitoba had used a 0.8 adjustment, while British Columbia made one-to-one adjustments if bond prices moved outside of a certain band.

Before the formula can be applied, a base ROE must be calculated. The benchmark ROE may be arrived at in a variety of ways, and is set in a manner similar to the setting of ROEs in the US. Equity risk premium (ERP) analysis, capital asset pricing model (CAPM) analysis and, less often, comparable earning analysis are all taken into consideration. Notably, the DCF method is given little to no weight, for a variety of reasons. For example, the NEB has acknowledged that the DCF test is theoretically sound, but raised concerns about practical difficulties.[18]

Not all major Canadian jurisdictions had implemented formula-based ROEs when US and Canadian returns began to diverge. However, the jurisdictions retaining case-by-case analyses seemed to set ROEs in a manner that was highly sensitive to changes in the bond markets.[19] One could therefore view the "formula" jurisdictions as price leaders who set the standard for following the decline in bond prices in the setting of returns.

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18 NEB, Reasons for Decision RH-2-94 (1994) §2.5.

19 See, Alberta Energy and Utilities Board (EUB), *Canadian Western Natural Gas Co. Ltd. 1997 Return on Common Equity and Capital Strucutre and 1998 General Rate Application*, Decision 2000-9 (2000). On page 65, the EUB states, "[t]he Board notes that interest rates and bond yields have significantly declined during the time frame… Consequently, this significant reduction in interest rates will have a major impact on the determination of a fair return for a utility."

The unique feature of the Canadian ROE formula is that is sets a gap between Canadian long bonds and the fair ROE, as shown in **Figure** 3. The only reason that the ROE does not move in lock step with the long bond is the *notion* that the spread grows/shrinks with the move in the bond, by a quarter of the bond's movement. We say "notion" purposely, because the formula's tie between long bonds and ROE is not based on financial evidence on the contemporaneous spread between what the market requires as a return on bonds as opposed to a return on equity investments in Canadian utilities.

This last point bears emphasis. For those jurisdictions that have adopted the formula shown in Equation 1, or those jurisdictions led by those who do, the only new evidence determining ROE in utility rate cases is the movement in long-bond interest rates. Nothing in the application of the formula, as a factual matter, attempts to gauge contemporaneous equity cost rates. Rather, the formula adjusts ROEs based on the historical observation that allowed ROEs move in the same direction as bond yields.

In this fashion, the Canadian formula diverges from attempts in the US to streamline cost of capital proceedings by implementing a generic formula for the cost of capital. There have been two highly visible attempts to do such a thing in the US, by the Federal Energy Regulatory Commission (FERC) in the late 1980s and by the New York Public Service Commission (NYPSC) in the early 1990s.[20] In both of those cases, the target of the generic formulae was the cost of equity, using contemporaneous market information with theoretical models designed specifically to gauge equity costs.

Neither the FERC nor the NYPSC methods ultimately resulted in an abandonment of a case-by-case examination of the cost of equity. The FERC methods have streamlined somewhat the construction of the "proxy groups" for gathering market information on similarly-situated regulated firms and have basically set the form of the theoretical formula for combining stock yields plus analyst growth rates (in the "yield plus growth" or DCF formula). Those streamlines aside, the FERC generally dropped its pursuit of a generic formula by about 1992 over legal concerns that a company-specific record must support the finding of a fair return. The FERC since has not departed from a case-by-case examination of the cost of equity. The NYPSC formula, for its part, was created after a multi-month process costing some millions of dollars. It, too, centered on a formula for deriving the cost of equity (rather than the long bond rates plus a pre-determined spread), but it was never adopted formally by the NYPSC.

IV. THE TRADITIONAL CASE-BY-CASE METHODS OF CANADIAN AND US REGULATORS

Rate cases in the US are relatively standardized affairs. This is not to say that US commissions never err in their decisions, that all commission decisions are objective or that rate cases are

[20] FERC Order 442 *Generic Determination of Rate of Return for Public Utilities,* Docket No. RM85-19-000; New York Public Service Commission, *Generic Financing Proceeding, Case* No. 91-M-0509.

never protracted battles. Property rights and US regulation are continually evolving and have only reached their current state through experimentation and judicial rebuke.

In an attempt to relieve the regulatory burden the FERC intended to move to a generic ROE approach in the 1980s with Orders 420, 442 and 461, and similar efforts were made by the NYPSC and the Federal Communications Commission (FCC) in telecommunications. However, the generic ROE pursued in these cases was never applied extensively and fell into disuse. US ROEs are now determined the same way they have always been determined: through discounted cash flow (DFC) analysis that examines a comparable group similar to the utility in question.

US gas utilities generally do not generally undergo annual rate cases.[21] Rather, the ROE stands until either the utility requests a rate case or the commission judges that conditions have changed enough to warrant a re-examination of rates. To streamline rate cases, commissions have objectivity standards that include the need for a theoretical justification of the methods used and all subjective decisions are justified in the public record. These standards help to ease contention in rate cases and limit the discussion to manageable issues.

In this section we will explore the methods used for rate setting in a case-by-case environment. We begin with the most popular method in the US, the DCF, before examining the CAPM and other ERP methods. Finally, we discuss the role of capital structures in case-by-case ratemaking.

A. Discounted Cash Flow (DCF) or "Yield Plus Growth"

The most popular method used to determine the ROE among US regulatory commissions is to determine what future stream of common dividends investors expect on a case-by-case basis using discounted cash-flow (DCF) analysis. Its popularity is a function of its ease of use and comprehension by finders of fact not necessarily particularly versed in financial theories. At its most fundamental level, the DCF method endeavors to compute the cost of equity capital by summing the two sources of equity investor returns—the "yield" portion (meaning the dividend yield with respect to the stock price) and the "growth" portions—the rise in the stock price that investors expect to see. In a world of complicated ratemaking formulae and financial theories, it is no surprise that "yield plus growth" has an intrinsic appeal, particularly when there are many sorts of similar utilities by which to gauge the sum of these two common-sense factors that make up the ROE. The formal statement of the DCF methodology grew out of Professor Myron J. Gordon's work on stock valuation models, which was first published in complete form in 1962.[22]

Part of the DCF formula that may not appeal to analysts and regulators is the growth rate expected by investors. That growth rate is inherently inscrutable, and in small capital markets

[21] California has annual adjustments to rates, but that is a unique US jurisdiction and not in any way an indicator of what happens in the rest of the country. The tortured experience associated with the lead up and aftermath of the California energy crisis of 2000-2001 continues to cast regulatory procedures there in a unique light.

[22] *See* Gordon, M.J. *The Investment, Financing and Valuation of the Corporation* (Homewood, IL: Richard D. Irwin Inc., 1962; reprint, Westport, CT: Greenwood Press, Publishers, 1982).

(such as many utility jurisdictions overseas), it is very hard to gauge investor expectations and thus to apply the DCF model. But in the US, where the model retains its great popularity, a robust industry of independent stock market analysts helps greatly. Both in print and on the web, disinterested estimates of utility growth rates are readily available to assist in the calculation of DCF-derived ROE figures. Combining these publicly-available growth rate estimates with the availability of a number of similar-risk companies, in "proxy groups," allows regulators to enjoy the stabilizing influence of the law of large numbers in setting the ROE.[23] For practical-minded regulators looking for stable, understandable and objective evidence, its popularity is no surprise.

DCF analysis involves making selections at two key stages: first, the analyst selects a specific "proxy group" of utilities facing similar risks and then selects the various of inputs such as the growth rate. Many of the practical concerns of Canadian regulators over these selections have been addressed in US jurisdictions, and the regulatory burden of case-by-case ratemaking has been lightened by establishing consistent selection criteria at each stage. One concern unique to Canadian jurisdictions, however, is the applicability of proxy groups that contain US utilities.

Given the degree of capital market integration, the degree of cross-border gas trade, and the international presence of several Canadian LDCs, we believe that a proxy group that includes US utilities facing similar risks would be appropriate for Canadian utilities. We will examine in Section IV whether the risks facing Canadian utilities are, in fact, comparable to those facing US utilities but, so long as Canadian regulators are attentive to potential macroeconomic divergence, we see no economic or financial factor that would confound the use of proxy groups that include US utilities.

B. Equity Risk Premium (ERP) and the Capital Asset Pricing Model (CAPM)

Equity risk premium (ERP) analysis is based on the observation that it is more risky to hold equity than bonds. Assuming that investors are risk adverse, they will require a higher return to hold assets with higher risk. Equity returns therefore carry a premium over bond returns. If risk-free bond yields could be identified and the equity premium could be estimated, the cost of capital will result.

There are a wide variety of methods for estimating the cost of capital along these lines, the most popular of which is the capital asset pricing model (CAPM). The CAPM formula itself is rather straightforward. Its components are: (1) the risk free rate of return; (2) the market rate of return; and (3) the beta. These inputs are combined to estimate the ROE.

[23] In practical terms, the "law" describes the stability of a random variable, with repeated sampling. That is, given a sample of independent and identically distributed random variables, the sample average will approach and stay close to the true population average as the size of the sample increases. This is a long way of saying that the ROE results from a "proxy group" sample of similar utilities are more representative of the actual ROE than the ROE for a single company alone.

$$ROE = Risk\text{-}Free\ Rate + \beta(Market\ Return) \qquad \textbf{(2)}$$

Despite this algebraic simplicity, there are different methods to obtain each of these components and to compute the required rate of return. The effects of choosing one method over another can substantially change the required cost of capital. Because CAPM, with the exception of the beta term, does not have the "law of large numbers" properties in a comparable group that the DCF has, there is less reason to focus primarily on a comparable group rather than the utility in question, especially when the beta is significantly different from that of the proxy group.

The practical elements of the CAPM formula are full of contention. For example, the beta term relates the movement in an individual company stock price compared with that of the entire market for stocks. Greater relative movement vis-à-vis the market means a higher beta. Those betas published by investment analyst houses (such as *Value Line*, Merrill Lynch or others) make use of an adjustment procedure that moves "raw" betas toward 1.0. The "adjusted" published betas are generally the ones used by US regulators when they make reference to the CAPM.

The other area of contention is the market return—defined as the premium that the market for equities demands as a spread on the risk free rate. Market risk premiums are not published, but have to be derived. Some are based on historical achieved returns and others try to gauge investor expectations on future equity returns not unlike those who perform a DCF analysis. In rate case application of the CAPM, there is always dissension among interested parties regarding the size of the market risk premium, as its choice directly affects the level of "just and reasonable" rates. Practical-minded regulators wrestle with this issue.

- Despite these areas of contention, one benefit of the use of the CAPM is that the theory upon which it rests provides a relatively clear method for gauging the effect of increased leverage, or "gearing," on the cost of equity. It is well known in both financial theory and in practical investment circles that a high proportion of debt in the capital structure adds financial risk to the business risk facing a company—and raises both the cost of debt and equity. The CAPM model provides a theoretical method to compute the effect of different gearing on the ROE.[24] Indeed, in some prominent cases in the US, the this method has been used as the basis for regulators to grant higher equity costs to adjust for the use of greater gearing levels as deemed prudent by the regulator.[25]

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[24] For the theoretical formula regarding the relationship between betas (and hence equity costs) and gearing, see: Copeland, T.E., and Weston, J.F., *Financial Theory and Corporate Policy, Third Edition*, Addison-Wesley, Reading, Massachusetts (1988), p. 457.

[25] For example, in the aftermath of the electricity utility restructuring in Texas, the Public Utility Commission there approved a 50 basis point "financial risk" premium to the cost of equity for all electricity distributors in the state to reflect its desire that the utilities all move toward a higher amount of debt in their capital structures (60 percent) reflecting the spin-off of their generating function. *See* Public Utility Commission of Texas, *Order No. 42: Intermin Order Establishing Return on Equity and Capital Structure*, Docket No. 22344 (2000).

CAPM is often used in US rate cases, but it is almost never used as the sole determinant of the cost of equity capital.[26] The judgment required in selecting parameters for the CAPM is no less significant than the judgment required for judicial use of the DCF, and the CAPM lacks the "central tendency" properties of DCF that smooth the results to yield a more reliable estimate.

C. Capital Structure

Modern financial theory suggests that there is a relatively wide zone of reasonableness for capital structures, with capital structures within that zone producing about the same cost of capital.[27] In the US, a utility's management is therefore granted a measure of discretion as to the type of capital raised. Having a solid level of financial integrity can provide rate stability and other benefits to customers, and commissions are reluctant to interfere with a utility's capital structure unless it is pushing the bounds of reasonableness.

In the US, the projected actual capital structure ratios of the utility at the time that new rates would go into effect are used to calculate a pre-tax weighted-average cost of capital. Because the rate proceeding will set rates to be charged for service in future periods, it is appropriate to base the capital structure components on the best available estimates for the period of time in which the rates will be in effect. Furthermore, the actual degree of leverage has important implications for ratemaking, as higher leverage raises financial risk and therefore the cost of capital.

Financial risk is the portion of total corporate risk over and above basic business risk that results from using debt.[28] Because equity investors are the residual claimants after the payment of debt, the cost of equity increases with higher debt ratios (*i.e.* with higher leverage). As a company increases the portion of debt in its capital structure, investors perceive a greater chance that there will not be sufficient returns available after the payment of fixed charges. Both the Modigliani-Miller theory, a the basis for the field of finance, and empirical tests of the theory confirm this inextricable link between capital structure and the cost of equity.[29]

The total cost of capital is therefore U-shaped with respect to capital structure. High equity percentages raise the WACC, but the WACC also increases at high debt percentages as investors seek higher returns on equity due to the increased financial risk.

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[26] One jurisdiction in our experience, Oregon, for some time in the 1990s and into the mid 2000s appeared to use the CAPM as the sole method for finding the ROE. It stopped that seemingly sole reliance in 2001. *See* Public Utilities Commission of Oregon, Order No. 01-777 (2001).

[27] *See* Morin, R., *Utilities' Cost of Capital*, PUR, Arlington, VA 1984, p. 268.

[28] Brigham, E.E., *Financial Management, Theory and Practice, Third Edition*., The Dryden Press, Chicago (1982), p. 861.

[29] *See* Copeland, T.E. and Weston, J.F., *Financial Theory and Corporate Policy, Third Edition*., Addison-Wesley, Reading MA (1988), Chapters 13 (theory) and 14 (empirical evidence and applications).

Hypothetical capital structures have been used in the US when it was judged that utilities were deviating from reasonable capital structures by either employing too much debt or equity in an effort to raise overall returns. Hypothetical capital structures may also be used if the utility is owned by a parent company that faces markedly difference risks from those faced by utilities and therefore carries a capital structure that would be inappropriate for a utility.

In such cases, the capital structure of a comparable group of utilities is used, on the basis that comparable groups' capital structures reflect the opportunity costs facing investors, satisfying the comparable investment standard. Very rarely would a capital structure be "deemed" in the US without consulting a comparable group and addressing why the actual capital structure chosen by the management is inappropriate.

V. RELATIVE RISK FOR CANADIAN AND US GAS UTILITIES

The previous two sections of this paper described how Canadian and US regulators have derived the ROE. This section investigates whether there is any justification for concluding that lower (higher) risks for utilities in Canada (the US) justify ten years of divergent returns.

In this section, then, we first examine more carefully which risks matter to utility investors. We then examine the practical boundaries to those risks for regulated utilities in Canada and the US and upon what legal and procedural foundations those risks rest. Finally, we examine whether there is any evidence available that allows us to conclude that the divergence in Table 1 stems from any persistently lower risk in Canada for gas distributors than that level we observe in the US.

A. What Risk Matters to Utility Equity Investors?

Any discussion of risk in the context of utilities invites controversy. Much of this, in our opinion, comes from a *colloquial* as opposed to a *technical* definition of risk in the context of ROE. In setting a fair compensation for investors in the ROE, the risks that matter are the ones for which those investors require compensation. Colloquially, all would agree that predicting the weather is *risky*, but to the extent that over time weather conforms tightly to averages, the rates set on average weather patterns carry no particular risk to investors' ability to recoup their cost of capital. That is to say, *weather risk* is not the same as *ROE risk*. For a natural monopoly gas utility whose costs are geared to serving customers with whatever local weather conditions exist, the weather does not stand between them and recouping their funds—and is not properly a part of the ROE.

Weather is merely one example of the need to focus on technical risk definitions in gauging the fairness of the ROE. While the cost of service may differ between US and Canadian utilities based on their distinct geographies and other factors, both can expect the opportunity to earn a fair rate of return that is based on the returns to an investment of comparable risk.

1. Regulatory Risk

The risk that a gas LDC faces is inherently intertwined with regulation. Gas LDCs are a natural monopoly—the only thing standing between an LDC and monopoly profits is regulation. The greatest risk to an LDC is the risk that the regulator will not allow the utility to recover prudent costs—including the cost of capital—in a timely manner.

2. Business Risk

The business risk faced by LDCs in Canada does not significantly differ from those in the US. There are forward-looking risks facing investors that are somewhat independent from regulatory risk. These risks are limited, however, as a utility has the right to call for a rate case if significant events (such as a recession) damage its ability to earn a reasonable return on its invested capital without an increase in prices—a recourse obviously not available to unregulated firms. Business risk is therefore an interaction between regulatory risk and the business environment and many business risks can be lessened, modified or even eliminated through various regulatory practices.

Forward-looking business risks include:

- *Long-Lived Assets*. Gas LDCs in Canada and the US connect to a multitude of consumers. Therefore, distributors are the ones charged with the planning of upgrades to networks that in many cases are decades old. The need for major expenditures to provide safe local service do not always follow rate case schedules, so there is often a lag between investments in long-lived assets and recovery of those costs in rates. Such risks in the cost of planning and engaging in ongoing local network maintenance are the same in both Canada and the US, and both utilize deferral accounts to mitigate this risk.

- *Risks of service interruptions*. Major or minor service interruptions are generally the responsibility of the distributor—as are the costs of remedying outages. Cracked gas mains, storm damage to electricity wires and sub-stations, are all the responsibility of the distributor, which can try to plan for—but cannot guarantee—the collection of all costs that are incurred.

- *Adequacy of depreciation*. The depreciation allowance included in distribution company rates is an estimate based on historic experience. Depreciation allowances may not consider economic obsolescence resulting from unanticipated technological change or potential large capital additions. As such, there is a risk that utility plant will be under-depreciated, and changes in technology or regulation may cause shareholders to bear the result of inadequate depreciation.

- *Risk of technological bypass*. Gas LDCs in Canada and the US are at risk of customers bypassing the network by switching fuels or adopting alternate technologies. If bypass is significant there is no guarantee that the remaining rates will be adjusted to recover the cost of abandoned or excess capacity.

- *Risk of the competitiveness of rates*. While LDCs are entitled to recover their actual, prudently-incurred cost of doing business, gas LDCs in Canada and the US are at risk for the continued viability of the overall business. Competitive pressures from distributed generation or alternate fuels could create a situation in which allowed revenues are not competitively viable.

- *Risk of timeliness and adequacy of allowed revenue levels*. Gas LDCs in Canada and the US face the need to increase distribution rates as costs increase. It is expensive and difficult to file for a small rate increase. Utilities would absorb such costs until they become large enough to justify the cost of a rate filing.

3. Financial Risk

Apart from the regulatory and business environments facing an LDC, investors face financial risk as well. Financial risk is the risk associated with carrying debt in the capital structure. Debt return (i.e., interest payments) are contractual obligations. Up to a point, raising utility funds with debt provides for a less expensive way to provide the capital needed to provide services to customers. But with greater proportions of debt, the risk that those interest payments will not be "covered" increases, and with it both the interest rate demanded by lenders and the return required by equity investors. This effect on required rates of return is well established and widely known.

Financial risk is generally taken into account in setting ROEs in US rate cases. To the extent that a regulated firm's capital structure mimics those of a group of its regulated peers, no adjustment is necessary for financial risk. One the other hand, if there is a difference between the firms in question and their peers, then an adjustment to reflect the differential financial risk may be necessary (as happened in a noteworthy case for all of the regulated electric distributors in Texas—where a 50 basis point premium for the ROE was permitted to reflect the regulator's desire for the distribution-only utilities to take on more debt).[30]

The question of financial risk appears to often be obscured in Canada, where the generic ROE is provided for all utilities in a jurisdiction, leaving the issues of financial risk to be deal with in a specific deemed capital structure to address the risks of a particular distributor.

B. What are the Practical Boundaries to Regulatory Risk?

With any investor-owned utility, the regulator and the utility have reciprocal obligations that are generally well recognized. That is, the utility operates the service and provides the capital needed to maintain and expand the facilities that allow the public to be adequately served. For its part, the regulator provides a stable regulatory environment, oversees the adequacy of services, and offers the utility a reasonable opportunity to earn a return on its investments.

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[30] See Texas PUC, *Generic Issues Associated with Applications for Approval of Unbundled cost of Service Rates Pursuant to PURA §39.21 and PUC Subst. Rule §25.34*4, Docket No. 22344.

Among its various duties, a key role for regulators is to signal, credibly, to investor-owned utilities' investors how their investments will be recovered in regulated charges.[31]

Such regulation is described in the economic literature as a "form of long-term contracting."[32] Canada and the US have proven over 100 years of natural gas regulatory history that they are able to honor the "long-term contract." The exact form of this long-term contracting has evolved throughout this history as regulators pushed against the regulatory boundaries, were reprimanded by courts, were given new direction through legislative action, and were chaired by individuals of various political inclinations as new executives were elected.

In mature regulatory jurisdictions with strong legal and administrative histories, such as Canada and the US, the regulatory compact represents a concatenation of: (1) strong primary legislation; (2) credible, comprehensive and transparent administrative procedures for making regulatory decisions and adjudicating disputes; (3) accounting regulation specifically designed for utility ratemaking; and (4) clear pathways for reliable judicial review of regulatory decisions. Newer regulatory jurisdictions around the world that do not have comparable bodies of regulatory precedent routinely use explicit contracts to express such principles.

1. Strong Primary Legislation

Canadian regulatory legislation is effectively very similar to that in the US, although Canada does not have all of the judicial precedent regarding the constitutional protection of private property that characterizes the US. Canada's regulatory compact is based instead on common law and "fundamental justice" but nevertheless does appear to be comparable the US in practice.[33] The US Constitution, especially the fifth and fourteenth amendments, provides the foundation that supports those protections in the US.

In Canada and the US, Supreme Court interpretations of this primary legislation define the legal limitations on regulators' ability to take action on charges that may damage the value of utility investors' property. The best known case is that of *Federal Power Commission v. Hope Natural*

[31] This mutuality of obligations is sometimes called the "regulatory bargain" or "regulatory compact," but those are merely convenient labels for how governments and investors have traditionally worked out how the public will be adequately served by private companies.

[32] Professor Oliver E. Williamson, an authority on the economics of transactions and regulation, noted that "[a]t the risk of oversimplification, regulation may be described contractually as a highly incomplete form of long-term contracting in which (1) the regulatee is assured an overall fair rate of return, in exchange for which (2) adaptations to changing circumstances are successively introduced without the costly haggling that attends such changes when parties to the contract enjoy greater autonomy." Williamson, O.E., *The Economic Institutions of Capitalism*, Free Press, New York (1985), p. 347. See also Victor Goldberg, Regulation and Administered Contracts, *Bell Journal Of Economics*, Vol. 7 (Autumn 1976): p. 426-448.

[33] Canada's equivalent to the US 14th Amendment, Section 7 of the Charter of Rights and Freedoms, states: "[e]veryone has the right to life, liberty and security of the person and the right not to be deprived thereof except in accordance with the principles of fundamental justice." As a relatively recent act, it remains to be seen exactly how "fundamental justice" will be interpreted but it has thus far been interpreted as more than simple procedural rights.

Gas, in which the Supreme Court set a standard for determining "just and reasonable" returns, a standard that has stood the test of time.[34] Canada and the US share a remarkably similar regulatory mandate and their "fair and reasonable" standards for utilities returns are almost identical. Indeed, Canada's *Northwestern Utilities v. City of Edmonton* anticipated the landmark US *Hope* case by fifteen years. Both established the opportunity cost of capital as the relevant standard by which utilities' returns should be judged.

The Supreme Court of Canada stated in *Northwestern Utilities*:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise…[35]

In the *Hope* decision, the US Supreme Court, by a vote of five to three, set a new standard for determining "just and reasonable" returns for investor-owned utilities.

> The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[36]

In *Bluefield*, an earlier case leading up to the *Hope* decision, the US Supreme Court defined the proper rate of return as follows:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties...[37]

In setting required revenues, a utility's returns would henceforth be measured by investors' possible earnings on alternative enterprises of similar risk. The Supreme Courts thus ruled that a utility's investments were safe from seizure (*i.e.*, a "taking") if regulators set charges to award returns consistent with investors' opportunity cost of

[34] *Federal Power Commission v. Hope Natural Gas*, 320 US 591 (1944).

[35] *Northwest Utilities v. City of Edmonton*, S.C.R. 186 (NUL 1929).

[36] *Hope,* 320 US 591, 603 (1944).

[37] *Bluefield Waterworks & Improvement Co. v. Public Service Commission of the State of West Virginia et al.*, 262 US 679, 693 (1923). The *Hope* and *Bluefield* decisions refer to two Constitutional Amendments. The Fifth Amendment, as interpreted by the Court, gave the Court jurisdiction over Congress in such matters. The Fourteenth Amendment, under the Court's interpretation, gave it similar jurisdiction over the States.

capital. These limitations on the discretion of regulators were not academic exercises. For the purposes of the future gas market, the *Hope* and *Northwest Utilities* decisions were critical. They sharply limited investor or shipper uncertainty regarding the ability of regulators to act in a manner that would damage the value of the assets that investors would devote to regulated enterprises.

2. Credible, Comprehensive and Transparent Administrative Procedures

Predictable regulatory or tariff-making practices are unlikely without a clear set of administrative procedures that bind the way that the independent regulators conduct their business. Canada and the US both provide stability to their utility investors through strong administrative procedures.

An important tenet of Canadian administrative practices is the common law right to procedural fairness. The Supreme Court of Canada has held that judicial and quasi-judicial bodies, but also other administrative decision makers, must follow common law principles of procedural fairness that include the right to be heard and the right to be judged impartially. [38]

The 1946 Administrative Procedures Act guides regulatory procedures in the US. Similar to Canada, it requires regulators to hold hearings, warn participants of impending rule changes, to allow participation in regulatory proceedings from the affected parties and to accept evidence (subject to cross-examination in those hearings). The late US Senator Daniel Patrick Moynihan explained that:

> The APA rests on a constellation of ideas: government agencies should be required to keep the public informed of their organization, procedures, and rules; the public should be able to participate in the rule-making process; uniform standards should apply to all formal rule-making and adjudicatory proceedings; and judicial review should be available in certain circumstances. Taken together with the Freedom of Information Act, an amendment to the APA that was enacted in 1966 and added to in 1974, 1986, and 1996, the APA was intended to foster more open government through various procedural requirements and thus to promote greater accountability in decision making.[39]

These are precisely the elements of "due process" in the administration of regulation. Indeed, the legal inquiries that resulted in the Administrative Procedures Act arose out of the general judicial concern (arising in the US in the 1930s) that regulating prices of investor-owned companies *at any level* represented a potentially unconstitutional taking of private property. That

[38] An important decision with regard to procedural fairness was *Nicholson v. Haldimand-Norfolk Reg. Police Commrs.*, where the Supreme Court of Canada significantly extended the rights to procedural fairness to non-judicial administrative decision makers and solidified the right to justification for a decision. *Nicholson v. Haldimand-Norfolk Reg. Police Commrs.*, [1979] 1 S.C.R. 311.

[39] Daniel Patrick Moynihan, *Secrecy: The American Experience* New Haven, Conn: Yale University Press, 1998, p. 157.

potential unconstitutionality, it was rightly thought, could only be prevented if a specific framework was applied for assuring the due process of regulatory decisions.

While Canada does not have an exact equivalent to the U.S. Administrative Practices Act of 1946, it does have an umbrella of provincial statutes, the charter(s) of the administrative decision maker(s), and the protection of common law, which includes previous interpretations as well as foundational justice and the founding principles of the constitution.[40] Through these channels, Canadian administrative procedures are equally well-established and effective as US procedures.

3. Accounting for Utility Ratemaking

The goals of effective and efficient regulation can be frustrated without a consistent, credible, and sustainable set of regulatory accounts. Strict accounting standards (*i.e.*, the Uniform System of Accounts) rarely leave US or Canadian energy utilities and their regulators in major dispute over basic financial issues (like profitability, depreciation expenses or the admissibility of particular costs).

Strong and transparent accounting standards were established over half a century ago in Canada and the US, but such is not the case in other, supposedly "mature" jurisdictions. For example, a major component of the reviews of British Gas conducted in recent years by both Ofgas (the gas regulatory body before Ofgem was created) and the Monopolies and Mergers Commission concerned basic accounting and finance items in an environment with no regulatory accounting standards.[41] This confusion in the UK over British Gas's rate of profits on its capital stock and the depreciation allowed on billions of pounds sterling of transportation assets represents a major risk to utility investors that is absent in Canada and the US. Canadian and US accounting standards would never leave major assets in question, as was the case in the UK and elsewhere following privatization.

4. Reliable Judicial Review

Effective limits on regulatory authority in systems with well functioning regimes come from the judiciary and other paths of appeal. In both Canada and the US, the fundamental legal limitations on the ability of regulators to take actions that damage the holdings of utility investors (in some way or another) come from well-known Supreme Court decisions. The Courts in both countries have found that the property rights of investors in regulated companies,

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[40] The provincial administrative practices acts include: *Statutory Powers Procedure Act*, R.S.O. 1990, c. S.22 (Ont.); *Administrative Procedures Act*, R.S.A. 2000, c. A-3 (Alta.); *Administrative justice, An Act respecting*, R.S.Q. c. J-3 (QC).

[41] *The Economist* has referred to UK regulatory accounting as a "fiddly bit of guesswork." (See: "Don't you just love being in control?" *The Economist*, May 18th, 1996.)

as well as the rights of the customers they serve, require strict regulatory attention to invested capital.

C. What are the Elements of Canadian vs. US Regulatory Risk?

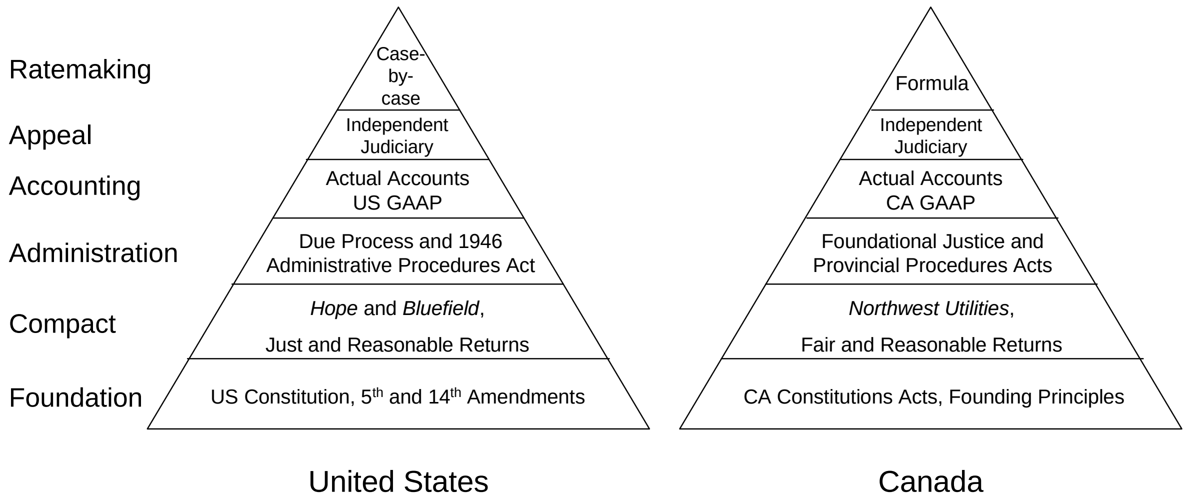
While Canada and the US share a credible regulatory environment, the exact regulatory foundations are admittedly not identical. However, the differences that do exist are more procedural than fundamental. The two jurisdictions engage in roughly the same practices, although they may go by slightly different names or receive more or less attention. The differing levels of attention does not imply that some practices are superior to others; rather, these differences arise from the dates the practices were implemented, the procedures used to handle the practices, and the emphasis placed on various practices in regulatory proceedings.

These principles are generally true of all regulatory jurisdictions in the US and Canada. Both equity investors and lenders generally give funds to utilities with the reasonable expectation the principles of obligations to be provided with a fair return will be honored. Even though the particular utility statutes may vary from jurisdiction to jurisdiction, and even though regulatory commissions may have different policies and precedents in different jurisdictions, investors anticipate the basic bargain between them and their regulator (who represents the public) will apply to their investments.

From the constitutional foundation through to administrative practices, accounting practices and judicial review, Canada and the US have virtually indistinguishable regulatory environments—so much so that the US *Hope* and *Bluefield* decisions are even cited in Canadian rate cases.[42] **Figure 4** illustrates the regulatory pyramid in Canada and the United states.

[42] See, for example, Alberta's *Generic Cost of Capital* decision, where the EUB stated, "[t]he Board concurs that the above decisions [*Northwestern*, *Hope*, and *Bluefield*] are the most relevant judicial authorities with respect to the establishment of a fair return for regulated utilities." Alberta Energy and Utilities Board, *Generic Cost of Capital* Decision 2004-052 (2005), p. 13.

Figure 4: Elements of Recent ROE Regulation in the US and Canada



Regulation in Canada and the US is founded on strong primary legislation that protects the rights of citizens. The constitution of Canada is an amalgam of codified acts and uncodified traditions and conventions.[43] The Constitutions Act, 1982 established a Charter of Rights and Freedoms, the Canadian equivalent to the US Bill of Rights. While the Charter extends many protections to Canadian citizens, including the right to "foundational justice," this Charter does not explicitly include the protection of property rights. A significant difference in the regulatory foundations is the strong constitutional protection of property rights in the United States afforded by the 5th and 14th amendments.

The regulatory compact in both countries is shaped by judicial decisions and includes the right to earn a "fair return" on investment, as determined by the opportunity cost of capital, which is termed the "comparable investment" standard. While the phrase, "regulatory compact," is not used as often in Canada as in the US, the concept is there. Indeed, the decisions that shape the US compact are cited in Canadian rate cases, and the Canadian decisions are widely recognized as establishing an effective compact that is very nearly identical to that of the US.[44]

While Canada does not have a single, federal administrative practices statue, administrative practices are highly refined in Canada and afford at least as much protection to investors as does the United States. The Canadian common law protection—enhanced by the introduction of foundation justice in the Charter of Rights and Freedoms and provincial administrative

[43] The Preamble to the Constitution Act, 1867 states that the provinces shall have, "a Constitution similar in Principle to that of the United Kingdom."[43] This has been interpreted as stating that the practices of the United Kingdom that were common before the creation of the constitution form part of the Canadian constitution—for example, the practice of an independent judiciary has been constitutionally guaranteed under this argument. See *Provincial Judges Reference* [1997] 3 S.C.R. 3.

[44] Morin, R.A. *New Regulatory Finance*, Vienna, Virginia: Public Utilities Reports (2006), p. 12.

procedures acts—equals the US standard of due process and the Administrative Procedures Act of 1946 in its protection of investors' rights.

In both Canada and the US, regulatory accounting is sufficiently refined that actual accounts are used for ratemaking without contention, avoiding the regulatory conflicts that surround benchmarked costs or replacement value accounting. The right to use actual costs for intraprovincial/intrastate regulation comes from provincial and state statutes. While some provinces have "fair value" mandates and are not required to use book values, they do so nonetheless.[45] This is similar to the US, where five states have "fair value" statues but have defined fair value to be the book value, so it is a difference without a distinction.

There is a perception that Canadian judiciaries are reluctant to interfere with the decisions of utility regulators. However, US judiciaries also do not overturn regulatory decisions without a clear reason to do so, and judicial rebuke is the exception rather than the rule in the US. Most important is that clear pathways for appeal exist in both countries and appeals are conducted in a manner such that, should major grievances be raised, the judiciaries are capable of reaching a reasonable decision.

Canada and the US share similarly mature regulatory compacts, supported by well-established accounting, administrative and appellate procedures. They are unique in their advanced regulatory environment based on credible, actual accounts. The greatest risk-determinant for utilities, regulatory risk, is comparable in Canada and the US.

D. Does the Continued Ability to Raise Capital for Canadian Utilities Indicate that All is Well?

Figure 1 drove this examination of the foundations of the regulatory procedures and risk. It shows that the allowed ROE was persistently lower in Canada that in the US over the previous decade. To the extent that this divergence is found not to be the result of different Canadian regulatory practices or lower regulatory risk vis-à-vis the US, but the result of the use of Canada's formula, an obvious question arises: would this cause investors to withhold funds from Canadian utilities?

In other words, is there any evidence that the Canadian utilities whose returns make up **Figure 1** have been unable to raise funds? If the generic Canadian ROE formula rests too heavily on long bonds and ignores genuine equity capital costs, the most manifest evidence that this is detrimental would show up in a difficulty for those companies in raising new capital. Conversely, does the continued ability of these Canadian utilities to provide adequate services in and of itself refute any possibility that the formula-based ROE is biased or inadequate?

[45] The use of actual accounts in Canada was upheld in *B.C. Electric Co.*, where the court established that the book value of prudently incurred costs could be used to provide a fair return, despite a statute requiring that appraisal value be used. *B.C. Electric Co. Ltd. v. Public Utilities Commission et al*. (1957) 13 D.L.R. (2d) 589 (BCCA).

We conclude that as a practical matter the answers to these questions are no. Absence of evidence that Canadian utilities subject to the formula are barred from the market for funds does not constitute evidence that those ROEs are adequate in the market.

There are times in the not-so-recent past when persistently inadequate returns have appeared for utilities in general. During two periods of high inflation in the 1970s and 1980s, US utilities faced wholly inadequate returns. Inflation, coupled with the need to construct new generation and transmission capacity, ruined the ability of traditional regulatory procedures to provide utilities with a reasonable prospect of earning an adequate ROE. In short, the traditional methods of regulating rates, using a test year, created a lag in the ability to recoup ongoing, inflated, costs that visibly affected the financial health of utilities.

Evidence that the utilities were suffering was clear in the stock markets, as utility stocks slid in relation to their book values. During both periods, it was common for utility stocks to be trading below the equity book value of utility investments (roughly the equity "rate base"). When this happened, any new equity raised by these utilities would "dilute" the equity of existing shareholders—basically providing a subsidy to new equity investors from old ones.[46] Such a subsidy could not continue forever, as it would doom an investor enterprise. As it happened, however, the problem—as highly visible as it was—was only relatively temporary.

No equity investors would willingly sell proportional rights to the future returns on the equity rate base for a discount—but they did so during this period anyway. Why? Given their overriding obligations to provide safe, adequate and reliable service to customers, they had effectively no choice in the matter. Inflation pushed up the cost of new funds to the extent that it reflected a subsidy from existing shareholders, but nothing during the years of high inflation left utilities off the hook regarding their own responsibilities to serve the public.

Fixing the problem required either a change in regulatory procedures to deal with high inflation (for example, using inflation accounting like in European or Latin American countries), or an end to high inflation itself. When inflation dropped in the US, utilities returned to business-as-usual. The prospect of high inflation is still a risk to which utilities have generally no defense except a strong belief that the central bank will work to prevent its recurrence.[47] But in no fashion was the continued investment in US utility infrastructures in the 1970s and 1980s evidence that the ratemaking formula wasn't damaging investor interests in periods of high inflation.

Similarly, the evidence that Canadian investors continue to provide safe, adequate and reliable service to their consumers cannot be taken as evidence, in and of itself, that the formula-based returns reflected in **Figure 1** are fair. The utilities in Canada are a mixture of closely-held subsidiaries (without traded stocks of their own) and publicly-traded firms. If the ROEs based

[46] See: Morin, R.A., *New Regulatory Finance*, Public Utilities Reports, Inc., Vienna, Virginia (2006), p. 364; and Hymay, L.S., *Americas Electric Utilities: Past, Present and Future*, Public Utilities Reports, Arlington, Virginia (1985), p. 262.

[47] Of course, bankruptcy is a defense against persistent confiscatory regulatory treatment, but that has only appeared rarely in the US, and then only in conjunction with other idiosyncratic events.

on the formula are unfair, it would be, in our opinion, beyond practical measures to try to discern objectively, as a separate matter, how it damaged the interest of investors. By its very nature the market's cost of equity is not easily and objectively measurable—which is precisely why regulators and analysis use indirect formulae like the DCF and CAPM. Reverse-engineering the effect of the Canadian generic formula is not a practical and objective possibility to measure the effect it has had on utility equity investments in Canada since around 1998.

Natural Gas Utility Return Determination in Canada:

Time For a New approach

A Discussion Paper Developed by the
Canadian Gas Association

April 2008

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Acronyms and Abbreviations

AAM	Automatic adjustment mechanism
CAPM	Capital asset pricing model
CE	Comparable earnings
CEA	Concentric Energy Advisors
DCF	Discounted cash flow
ERP	Equity risk premium
FCA	Federal Court of Appeal
FRS	Fair return standard
LDC	Local distribution companies
M/P	J.C. Major, R. Priddle
MRP	Market risk premium
NEB	National Energy Board
NERA	National Economic Research Associates
OEB	Ontario Energy Board
RfD	Reasons for decision
ROE	Rate of return on equity
S&P	Standard and Poor's
TSX	Toronto Stock Exchange

Table of Contents

Introduction

One of the most contentious, and long-lived issues for Canada's natural gas distribution industry is the determination of what a regulated utility should be allowed to earn on its investment in the equipment, operations, facilities and people required to provide natural gas services to the public.

Because natural gas utilities are not competitive free market enterprises, there is no "invisible hand" of an open market to keep costs and profits in check. Instead, it is up to the regulators and regulated utilities to determine the costs, risks and return of supporting the enterprise's operation.

While accounting records, purchase orders, payroll records and other documentation can accurately establish the costs expected for the utility, in the absence of competitive market pressures, it is not possible to directly observe the appropriate return to owners of a regulated utility.

Over the past year, the Canadian Gas Association (CGA) and other associations and utilities have been looking into the various aspects, issues and information surrounding the process of determining an appropriate return on capital. What many are finding is that since the adoption 14 years ago of a formulaic approach to determine fair returns, there have been a growing number of indications that the process is no longer producing appropriate results.

In June 2007, Concentric Energy Advisors (CEA) completed a report for the Ontario Energy Board that concluded that the current rate of return on equity (ROE) differential between Ontario/Canadian and comparable US gas utilities of 150 to 200 basis points was largely due to the formula itself and its reliance on trends in Canadian government bonds. It also found that there were no fundamental risk differences between Canadian and US natural gas distribution utilities that would warrant such a gap.

In February 2008, in a report commissioned by CGA, National Economic Research Associates Inc. (NERA) confirmed CEA's findings of a significant, systemic gap between comparable Canadian and US gas utilities. NERA also concluded that the gap was not warranted on risk differences and that the use of US comparisons were indeed valid given the shared Canada-US legal foundations and the integration of the two financial markets and economies.

In March 2008, CGA released a report entitled "The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications" (M/P) that focussed on the legal foundations of return determination in Canada. In the report, authors former Supreme Court Justice, John C. Major and former National Energy Board Chair, Roland Priddle reviewed the history of the Fair Return Standard (FRS) in Canada and the US. The authors conclude, among other things, that the mechanistic nature of the formula approach often suspends the use of informed judgement. The resulting gap that has developed between US and Canadian ROE awards, the report maintains, is an indication that the required standard for returns is no longer being met in Canada.

This paper reviews and summarizes a number of the observations made in the above-mentioned body of research regarding return determination for regulated natural gas utilities. It examines the issues and outstanding questions relating to return determination in the context of the economic, financial and business environment in Canada today and for the past 30 years. While many of the issues raised in the paper have arisen in regulatory proceedings over the past decade, several perspectives are new. Among these are the broader time perspective pertaining to the long trend away from the FRS, the importance of the need for considered regulatory judgment in the use of formula approaches and the appropriateness of the comparison with returns in US utilities. This paper is offered as a means of contributing such perspectives to the ongoing debate.

Section 1: Current Legal Underpinnings for Utility Return Determination

Given the lack of open market forces to drive the determination of returns for utility investors the process has instead been grounded in a legal determination of what constitutes "fair".

In 1929, the Supreme Court of Canada in Northwestern Utilities Ltd v. Edmonton [1929] S.C.R. 186 (Northwestern) defined the scope of the utilities' right to price their product and their right as a result to a fair return. The Court stated:

"*By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.*"[1]

In 1994, the British Columbia Utilities Commission became the first regulator in Canada to adopt a generic formula approach to return determination. Then, in 1995, the NEB also adopted a generic cost of capital approach to setting utility returns. Other provincial regulatory boards have since followed suit and today apply an essentially uniform generic formula approach to setting returns.

In 2004, the Federal Court of Appeal (FCA) added some depth to the definition of fair return in TransCanada PipeLines v. Canadian National Energy Board 2004 F.C.A. 149, where the court confirmed that a fair return need not be modified out of deference to its impact upon customers. It was determined that regulators are free to use constructs like deferral accounts and other mechanisms to spread out the impact of commodity costs and weather impacts on the customer rates. However, the law explicitly states that regulators cannot simply reduce the return to the investor/owner as a mechanism to avoid potential increases in customer rates. Canadian law in effect requires that a fair return be provided for the services rendered by the utility. This "fair return standard" and its requirements remain in full legal effect today.

Further practical guidance as to how to functionally apply the FRS evolved from the National Energy Board (NEB) in its RH-2-2004 Phase II Decision, where it stated:

"*The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:*

- *be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);*
- *enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and*
- *permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).*"[2]

Notable in the legal definition of the FRS is the court's recognition that it is in the best interest of the utility and its customers to tie society's need for the essential service provided by the utility to the long-term viability of the utility.

The question then, is whether returns to Canadian natural gas utilities are meeting the required standards designed to ensure this long-term service and viability.

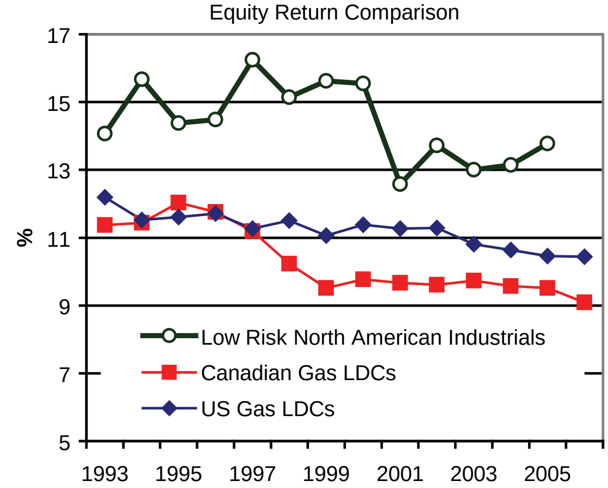
[1] Supreme Court of Canada in Northwestern Utilities Ltd v. Edmonton [1929] S.C.R. 186 (Northwestern).
[2] National Energy Board in RH-2-2004 Phase II Decision.

Section 2: Canadian Returns in Comparative Perspective

A simple illustration of the possible problem with utility return determination in Canada can be seen in a comparison of the returns to US natural gas utilities. (Fig. 1 & 2) In CGA's 2007 report entitled "Return on Equity: Allowed Returns for Canadian Gas Utilities" it was shown that a significant gap has emerged between Canadian and US returns.

Figure 1

Equity Return Comparison



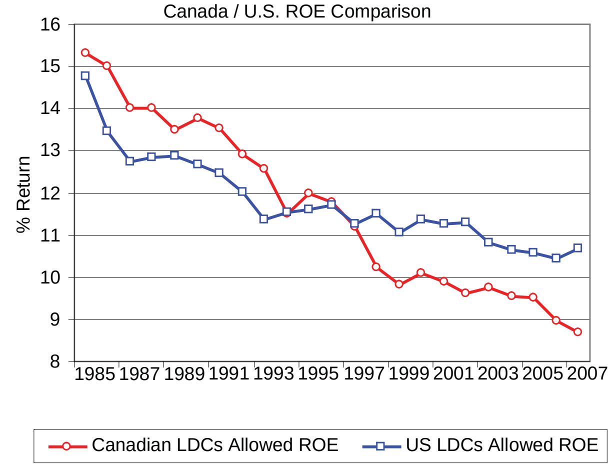
Source: Canadian Gas Association, S&P Insight

Confirmation of this discrepancy came in an Ontario Energy Board (OEB) –commissioned report carried out by Concentric Energy Advisors (CEA). In their report, CEA shows (Fig. 3) that Canadian utilities are consistently and markedly below a reasonably constructed representative group of their US-based peers.

While it is possible to compare Canadian natural gas utilities only to each other, the uniform use of the formula approach to return determination in Canada makes such a comparison circular in both its logic and result. A Canadian peer group could potentially be made from a properly constructed group of low-risk industrial enterprises. However, efforts to introduce such comparisons have tended to founder on the difficulty in identifying enterprises that are sufficiently comparable to that of a natural gas utility.

Figure 2

Canada / U.S. ROE Comparison



Source: CGA, Regulatory Research Associates (RRA)

Alternatively, one can reasonably ask whether US-based utilities are an acceptable peer/comparator group. This question was also addressed by the CEA report in which they state the following:

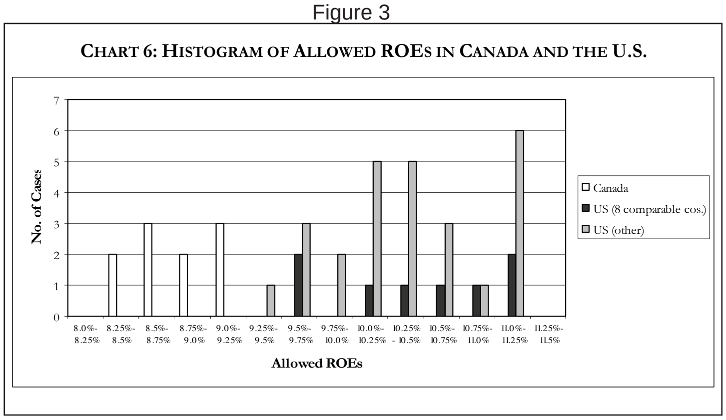
"*While specific characteristics of individual gas utilities and their respective regulatory environments can lead to differences in allowed returns, there are no apparent fundamental differences between gas utilities in Ontario and those in the US that would cause a sizable gap in ROE. In other words, taken as a whole, US gas utilities are not demonstrably riskier than Canadian gas utilities.*"[3]

The issue of the appropriateness of comparison to US natural gas utilities was further investigated by NERA in their CGA-commissioned report entitled "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis". In their report, NERA concluded the following:

"*Canada and the United States have almost hundred-year histories of regulating investor-owned utilities. This shared experience is different from almost all the rest of the world, where the appearance of investor-owned (i.e. private) utilities came only with the privatization wave of the late 20th century.*" […] "*These two national jurisdictions thus share a common heritage that is quite different, for example from the newly-privatized regulatory*

[3] "A Comparative Analysis of Return on Equity of Natural Gas Utilities," p. 2, prepared for the Ontario Energy Board by Concentric Energy Advisors, June 14, 2007.

Figure 3



jurisdictions in the rest of the world. Those jurisdictions overseas regulate their investor-owned utilities on an institutional basis quite different than in Canada and the US – two countries that share the longest, largest and most unencumbered trade border in the world. It is thus a fair question to compare and contrast Canadian and US utilities with each other to examine how their regulators deal with them and, in particular, derive the ROEs used to set their regulated tariffs.”[4]

Further questions about the validity and meaning of a divergence between the Canadian and US allowed return levels are raised in a study published in the autumn 2007 edition of the Bank of Canada Review.[5] The study notes that the higher the risk to future returns, the higher those expected returns must be to compensate investors for taking those risks. According to the study, Canadian firms show a higher degree of financial leverage, a higher variability (dispersion) in future earnings, lower stock market liquidity and lower corporate taxes. Combined, these factors in part explain an observed higher cost for equity financing in Canada. Yet, since the introduction of the formula approach to return determination in Canada, utility returns have declined markedly as compared to their US counterparts, a move exactly contrary to that suggested by the Bank of Canada, CEA, NERA and others.

The comparability called for in the FRS appears to have diminished, at least in part, due to the difficulties, perceived and otherwise, in undertaking such an effort. In contrast, in the US, significant efforts are made to compare utility returns to an agreed peer group. Indeed, such comparisons are the very foundation for regulatory board return decisions in that country.

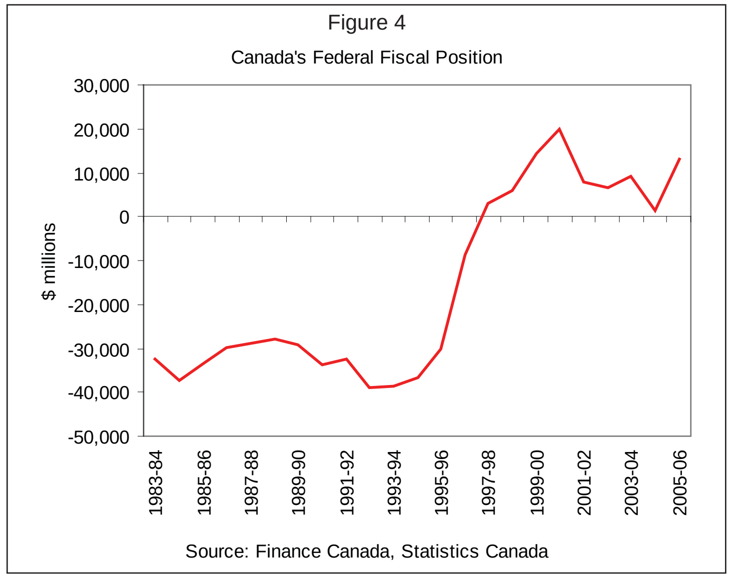
[4]“National Economic Research Associates Inc., “Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis,” p. 4, p. 6, February 2008.
[5] Estimating the Cost of Equity for Canadian and U.S. Firms, Bank of Canada Review, Autumn 2007.

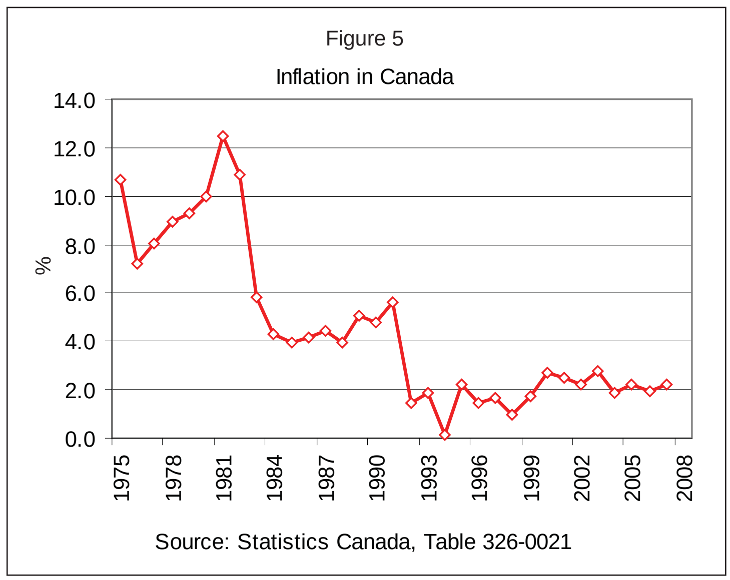
SECTION 3: THE FORMULA APPROACH AND CHANGES IN THE MACRO-ECONOMY

In the 14 years since the introduction of the formula approach to return determination in Canada the economic, financial, and business landscape has changed markedly. Of particular importance are the changes witnessed in the various measures that influence the formula-based approach, specifically, government debt levels, inflation, interest rates, and the performance of Canada's economy.

Some experts contend that it is counter-intuitive that such variables should be the driving factors behind return determination for Canadian gas utilities at all. In a recently published article, Roland Priddle, former Chair of the National Energy Board stated:

"It's now hard for me to see that long-term bond yields, driven by factors as disparate as governments' efforts to get budgetary deficits in hand, central bank' concerns (or not) about inflation…are somehow going to provide a continuing, reliable proxy for returns available in businesses presenting degrees of risk similar to gas pipelines and distribution enterprises."[6]





Canada's Fiscal Deficit

In the 10 years immediately prior to the introduction of the formula approach, Canada regularly ran multi-billion dollar annual deficits, racking up massive amounts of government debt. Then, almost coincident with the introduction of the generic approach, Canada started to get its fiscal house in order. (Fig. 4)

With today's hindsight, we can now see that the financing requirements generated by these huge deficits meant that Canadian bond rates were necessarily quite high. Indeed from 1976 to the end of 1996, the average interest rate differential between Canadian and US long bonds was just shy of 150 basis points. In the 10 years from 1996 to the end of 2006, this differential has averaged just under 50 basis points.

Canada's Inflation

Inflation in Canada had also been roaring along in the late 1970's and early 1980's, at times at double digit levels. (Fig. 5) As a result as we entered the 1990's investors seemed to expect inflation and currency depreciation that was out of line with the anti-inflation monetary policy that was by then being consistently pursued by the authorities. The credibility of inflation policy was also undermined by large budget deficits and by political concerns about the possibility of Quebec separation. It was not until the second half of the decade that inflationary expectations were reined in as deficits were largely eliminated, inflation was kept low, and political uncertainty abated somewhat.

[6] Roland Priddle, "It's Time for the Next Evolution in Regulation," The Gas Journal of Canada (2007): A9.

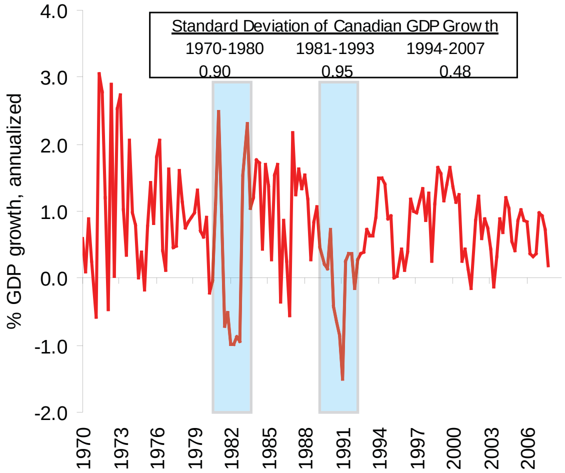
Canada's Economic Performance

The decade prior to the formula adoption also saw Canada's economy weather two large recessionary periods (Fig. 6), the first in the early 1980s, and then another in the early 1990s. These economic dislocations came on the heels of a very volatile pattern of economic growth that had characterised the 1970s. In general, in the 20 years prior to the adoption of the formula approach, there was twice as much volatility in Canada's economy compared to that seen in the 15 years since then.

Not surprisingly, these recessionary periods caused significant turmoil in terms of business risk, profitability, and the stability of corporate earnings.

Figure 6

Canada's Economic Growth



Source: Statistics Canada

Implications

In sum, the formula approach was adopted at the end of a period whose macro-economic circumstances would subsequently prove to be atypical of the period over which the formula was destined to be applied. What this says about the future is of course unclear but it does underpin the contention that a formula left, in effect, on automatic pilot for an extended period risks producing outcomes which do not accurately reflect economic and business realities.

SECTION 4: IMPACTS ON RETURN DETERMINATION IN CANADA

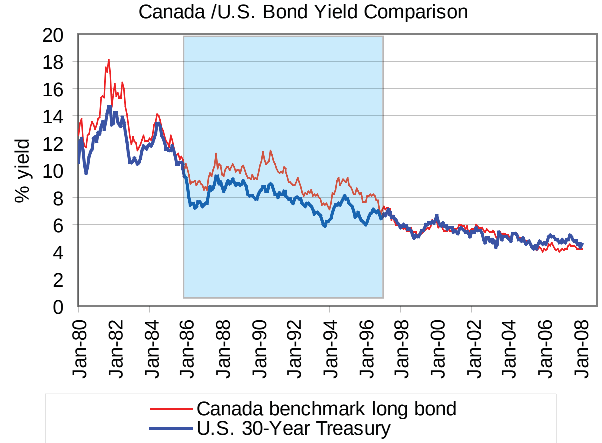
Bond Markets and Return Determination

The economic and market volatilities and instabilities of the 1980s and early 1990s had a profound influence on which methods and methodologies regulators and stakeholders saw as preferable. These influences were enunciated by the NEB in 1994 at its last rate hearing prior to the generic cost of capital proceeding where the Board found that:

"…in the light of recent and prevailing financial market conditions, neither the Discounted Cash Flow (DCF) test nor the Comparable Earnings (CE) test currently yield reliable results. … Accordingly these tests were given little or no weight in the Board's decision." Instead, the Board was of the view that "…the ERP [equity risk premium] was the primary measure of investors' required returns in the circumstances of this case." However, the Board was careful to state its view that these tests (CE, DCF) may prove useful under different economic conditions."[7]

Figure 7

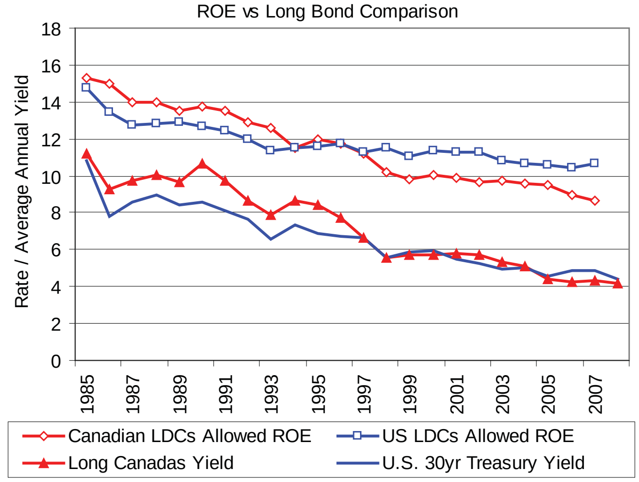
Canada /U.S. Bond Yield Comparison



Source: U.S. Federal Reserve, Statistics Canada

Figure 8

ROE vs Long Bond Comparison



Source: Statscan, Bank of Canada, US Fed, RRA,CGA

In the face of this instability, Canadian regulators were pushed towards risk-based return determination methods that were based on the relatively "calm" bond market. The availability of credible historical data and independent credible forecasts certainly made this seem like a safer foundation for a formulaic approach to return determination.

What can now be seen with hindsight, however, is that government bonds yields in Canada in the early 1990s also had a number of risk elements that made them an equally poor basis for a formula approach to return determination. The same high government annual deficit and high inflation that contributed to volatility in equity comparisons were adding a "risk premium" to Canadian bond yields illustrated by the divergence from yields afforded their US equivalents. (Fig. 7, shaded area).

NERA addresses the impact in their report, wherein they concluded:

"The apparent efficiency of bypassing case-by-case evidentiary proceedings with a generic formula may have foretold a new and more efficient method of deriving regulated rates generally—except for one thing. The new Canadian generic ROE formula appears to have created a persistent divergence between allowed gas utility returns in Canada and the US.…That is, in dozens of evidentiary proceedings since 1998, US regulators have allowed their companies to set tariffs reflecting ROEs that were on average substantially higher than for their Canadian formula-driven ROE counterparts."[8]

[7] J.C. Major, R. Priddle "The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications", pg. 14, March 2008.

[8] National Economic Research Associates Inc., "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis," p. 4, February 2008.

This observation echoes CEA's findings that prior to the formula-approach, Ontario utilities exhibited the expected higher return as compared to their US counterparts. Figure 8 illustrates this point.

The NERA report picks up on this fact and goes on to explain that the explicit and independent use of comparative return information in the US confirms the validity and impartiality of those results, and that the counterintuitive Canadian result of lower returns, despite an equally risky basis, if not more so, illustrates the systemic downward bias in Canadian return determinations processes.

NERA concludes that it is the formula itself that is driving the result:

"*The Canadian ROEs produced by the generic Canadian ROE formula are biased downward. The formula has, since its inception, ridden on autopilot the declining Canadian long-bond interest rates (the cost of a kind of debt) with no independent check on the cost of equity. The generic Canadian formula might not always be biased, and indeed in an era of stable interest rates and equity markets it may have held a true course for many years. But it has been overtaxed by the relatively unprecedented decline in interest rates since the late 1990s. The uncorrected, un-calibrated formula—not risk differences or inherent Canadian regulatory differences—has driven the divergence between observed Canadian and US ROEs.*"[9]

The current form of Canadian formula approach, chosen because of the nature and circumstances of the equity market, bond market, and economic history that formed the very landscape of its birthplace, does not fit the circumstances of today.

[9] National Economic Research Associates Inc., "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis," p. 8, February 2008.

Section 5: Responding to the Impacts: Reconnecting to the Cost of Equity

Reestablishing the cost of equity in Canada

The now-favoured capital asset pricing model (CAPM) approach to return determination is driven by the current level of interest rates and the relationship between the risk-free rate of return and the return of the equity market.

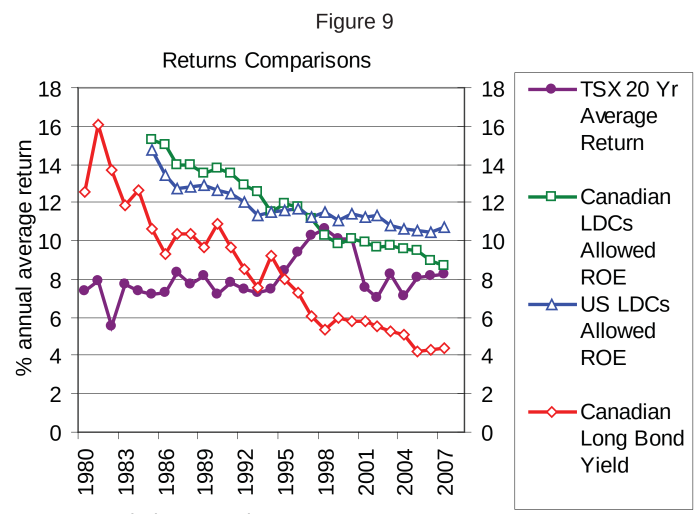
But a simple ex-post check shows how the cost of equity has evolved along quite a different trajectory than the cost of debt (Fig. 9). As a result, the aforementioned influences related to the broader macro-economy appear to have caused utility returns, based essentially on the cost of debt, to track off course.

In the US, a more explicit consideration of cost of equity is commonly applied using peer/proxy group return methodologies of DCF and CE. As a result US gas utility returns do not track US long bond yields as closely (Fig. 10), and have remained more in line with the broader cost of equity in North America.

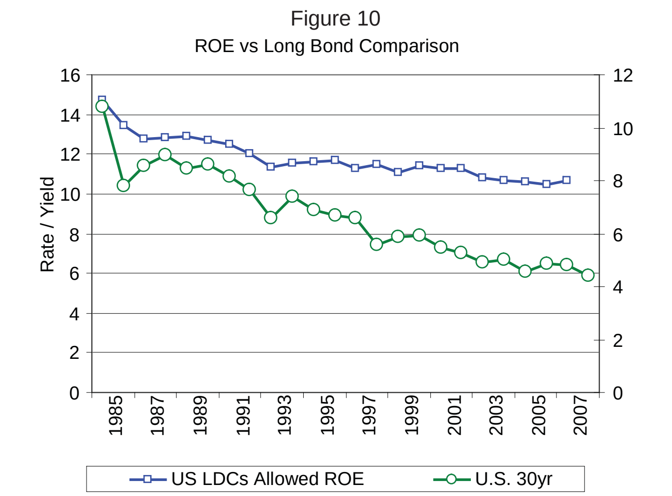
In the US, comparison-based methodologies benefit from the existence of a larger, more stable group of comparable publicly traded utilities. That said, as argued earlier, Canadian utilities are sufficiently comparable to the US to justify use of US peers/ proxies in Canadian return determination. In their report CEA did just that, applying a standard US process to establish an acceptable peer group to accurately quantify the difference seen in Canadian and US returns and concluded:

"*There are many similarities between these two groups of companies (i.e., Canadian and US gas distributors) …and any differences in the metrics studied above do not appear to justify the overall ROE differential.*"[10]

What is also apparent is that the use of peer groups requires more judgement in the return determination process, a fact recognized by the NEB in 1971 when it observed the following:



Source: Statistics Canada; CGA



Source: US Federal Reserve, RRA, CGA

"*Many tests and techniques for assisting the process of reaching a just decision have been used …but no single test is conclusive, nor is any group of them definitive: whatever test may be used, in the last analysis the adjudicating body cannot escape the responsibility of exercising judgement as to what, in a stated set of circumstances, is a just and reasonable return or rate of return*".[11]

[10] "A Comparative Analysis of Return on Equity of Natural Gas Utilities," p. 36, prepared for the Ontario Energy Board by Concentric Energy Advisors, June 14, 2007.
[11] J.C. Major, R. Priddle "The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications", pg. 13, March 2008.

To underscore the above point it is worth repeating how circumstances have changed and how these changing circumstances have undermined the validity of the formula. The formula is stable provided that there is a stable or at least predictable relationship between the cost of equity and the cost of debt – essentially the equity risk premium. Plausibly, and consistent with the evidence of the past 14 years the ERP will tend to compress in high interest rate circumstances and expand in low interest rate circumstances.

The automatic adjustment mechanism adjusts the annual allowed return by a fraction (currently 75% in most Canadian provinces) of the change seen in the long bond. However in their study, the CEA found that this factor is almost twice as large as the relationship seen between allowed returns and long bonds in the US where the two returns are not systematically linked to the each other. [12]

[12] "*… for every one percentage point change in interest rates, the Ontario ROEs change by 86 basis points while U.S. ROEs change by 46 basis points.*", A Comparative Analysis of Return on Equity of Natural Gas Utilities," prepared for the Ontario Energy Board by Concentric Energy Advisors, June 14, 2007, pp. 16-17.

Section 6: Objections Raised

Over the past year CGA has been discussing the issues around returns on capital with a wide range of stakeholders, regulators and policy makers. In these discussions several objections have been raised which we believe can be readily set aside. For that reason we have addressed them in the following section. The essential concern is set out in bold followed by our responses, most of which are based on the other research cited in the paper.

Canadian gas utilities can still raise money and have not shown any signs of distress so their returns must be okay. They do not "need" a higher return.

- The courts have confirmed that the law requires that the three pillars of the FRS be met. This ties together the consumers' need for viable long-term services and the long-term viability of the regulated utility. Regulated utilities must, as required by law, be allowed to earn a fair return on their investment having regard to their duty to provide service. They can neither easily divest nor responsibly stop providing services. This objection shows a lack of understanding of the fundamental nature of the legal rights and obligations of a regulated utility in Canada.

You just can't use the US for comparison; US utilities work under different fact circumstances, including a riskier investment environment.

- As NERA and CEA concluded, the US industry is highly comparable to Canada on a legal, financial, and risk basis. As such, there are no fundamental differences that would justify the persistent gap seen between returns in Canada and the US.
- In fact, Bank of Canada researchers observe that Canada is a higher risk environment and generally the cost of capital in Canada is actually higher than in the US. Canada's smaller, less liquid, more leveraged, and more variable earnings environment are the main reasons for this observation.

Even if US returns are higher there is no reason to conclude that Canadian returns are too low; rather US returns may be biased upward

- Given the wide dispersion of US returns (albeit all higher than Canadian) returns this assertion is counterintuitive. Quoting NERA: "*Those regulators in the US who failed to find a suitable way to streamline their ROE procedures continued on the former path common to both Canadian and US regulation – to examine anew, in every tariff case, expert evidence on ROE for the company in question for the relevant period of time. We do not believe that either Canadian or US regulators would consider the results of those case-by-case evidentiary procedures to be biased on a large scale. They are perhaps expensive, time consuming or overwrought – but not biased.*"[13]

New rate-setting mechanisms, like incentive-based rates, will allow utilities that are more productive to earn higher returns, so they do not need higher allowed returns.

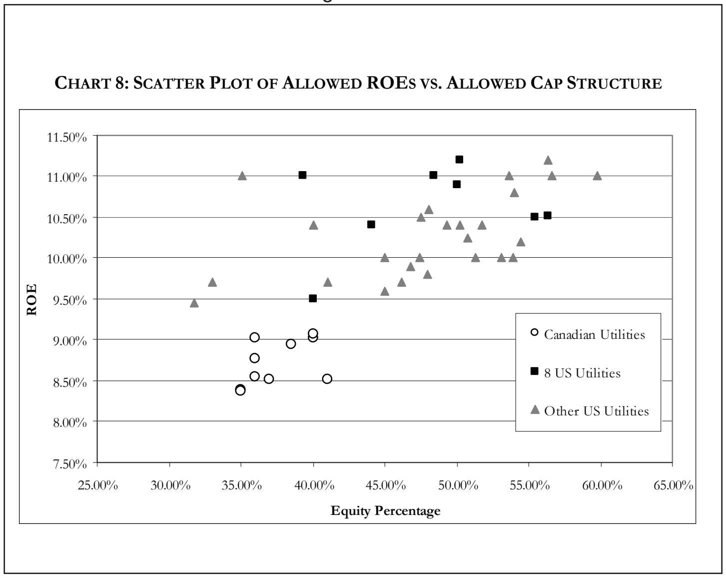
- As outlined by M/P "*Earnings from incentive agreements are rewards for extraordinary cost-savings and for entrepreneurship in devising service offerings that create value for which shippers (customers) are willing to pay. As the Federal Court of Appeal reminded in the 2004 TransCanada decision, the fair return must be determined independently of its impact upon resulting customer rates.*"[14]

Allowed returns are only a part of the total return available to Canadian utilities. They have received increases in their "equity thickness" that compensate them for their lower return on equity.

- In their report, CEA observes that Canadian utility allowed returns and equity thickness are both well below their US comparators (Fig. 11). This fact goes counter to the observed open market where higher leveraged equity investors seek higher

[13] National Economic Research Associates Inc., "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis," p. 5, February 2008.
[14] J.C. Major, R. Priddle "The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications", pg. 20, March 2008.

Figure 11



equity returns to compensate them for the extra risk of that leverage. It also runs counter to the fundamental legal principle that what is at issue is a "fair return on the total capital invested", a principle that dates back to the Northwest Utilities Case in 1929 and reaffirmed by the NEB since that time. Since, in Canada, both ROE and equity thickness are systematically lower than US comparators, the effect is to even further bias the return downward when looked at in the perspective of total return on capital.

Canadian utilities have a tax advantage on items like dividends from utilities that make our lower returns justified.

- CEA concludes in their report that "*In and of itself, it is not evident that the dividend tax rules in one country versus another would lead to differences in ROE on a comparative basis.*"[15]

Allowed return on equity masks the reality of what utilities actually earn and that would be a more valid basis for comparison.

- NERA concludes that "*…under both the Canadian and US regulatory methods, the ROE is the measure of cost of capital that enters the formula to make "just and reasonable" rates. It is the measure of compensation allowed for the capital that investors devote to the service of the public at the time the rates are set. What utilities actually achieve in profitability, however, is a different matter. The actual returns are a reflection of myriad factors, including management effectiveness, sales growth, macro-economic considerations, changes in capital costs, and even the weather. The regulatory treatment of investor-owners is tightly bound to the ROE. Clearly, ROE is the proper metric for comparison.*"[16]

Any changes to the determination of returns for Canadian utilities must preserve the results of past regulatory decisions. These decisions were made with full consideration of the facts of the time and as such are, by definition, fair.

- The authors of Canada's formula approach correctly expected a regular review of its results to ensure fairness. The systemic bias that has seen Canadian returns become disconnected from a reasonably formed comparator group indicates that the comparability called for in the FRS is not being maintained. This risks disconnecting the tie between the consumers' long-term need for viable energy services and the long-term viability of natural gas utilities in Canada. While some regulators have reviewed the formula since its inception and while many of the issues raised in this paper have indeed been brought forward already, the long term trends indicated in the CEA and NERA reports were not available at the time of those reviews. In addition, there has been controversy regarding the relevance

[15] "A Comparative Analysis of Return on Equity of Natural Gas Utilities," p. 41, prepared for the Ontario Energy Board by Concentric Energy Advisors, June 14, 2007.

[16] National Economic Research Associates Inc., "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis," p. 7, February 2008.

of comparisons with US LDC returns. By accepting the validity of a US comparator group regulators could resolve the dilemma such as that faced recently by BCUC who in their March 2, 2006 Decision accepted the principle that comparative returns should be considered but were unable to give weight to the proposition because of concerns about sample size, stating it was "*unable to give any weight to the Comparable Earnings of low-risk Canadian industrials in this proceeding, although it believes that this approach may play a role in future hearings.*"[17] Both the NERA and CEA reports address this issue and conclude firmly that the US comparison is valid.

[17] "Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism" British Columbia Utilities Commission Decision March 2006.

Conclusions

Various studies over the past year have confirmed a persistent divergence between returns awarded to Canadian natural gas utilities and those awarded to a plausible and reasonably formed comparator group. This divergence is primarily due to a systemic bias in the Canadian formula approach and is not explained by differences in the risks to Canadian utility investors nor is it due to a systematic bias in the return determination process employed for the comparator group.

The macro-economic and market circumstances that prevailed at the time when Canada was moving to a formula approach to utility return determination led stakeholders to seek a stable base such as the Canadian long bond. But in retrospect we see that those circumstances have changed significantly and the stability of the relationship between the cost of debt and the cost of equity has declined dramatically.

The systemic bias evident in Canadian formula-based utility return determination and the significant gap that has emerged between Canadian ROE and US ROE levels warrants a Canadian proceeding to redetermine the cost of equity to gas utilities and to establish an improved approach in future The following processes and principles would help ensure a sound and enduring approach.

- There is a need to rebase Canadian ROE's based on a comprehensive review of the cost of capital using all accepted approaches including comparison with a broad comparator group extending across all reasonably comparable industrial groups and jurisdictions including the US.

- There is a need to refresh the formula. In order to meet the requirements of transparency and stability the formula would need to be established on a reasonably stable and readily observable base with an adjustment factor that accounts as fully as possible for the changing relationship between the cost of equity and the cost of debt.

- The formula should be allowed to stand for no more than five years (and probably not less) after which there would need to be another comprehensive cost of capital review which brings in other methodologies and comparators.

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