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VIA RESS, COURIER AND EMAIL

September 9, 2009

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

Dear Ms. Walli:

Re: Consultation on Cost of Capital
Enbridge Gas Distribution Inc. Written Comments
Board File No.: EB-2009-0084

On September 8, 2009 Enbridge Gas Distribution Inc. ("Enbridge") filed written comments to the Ontario Energy Board ("Board") regarding the Cost of Capital Consultation proceeding. Enbridge's submission consisted of three parts; Enbridge's written comments, and two consultant reports from Concentric Energy Advisors ("Concentric") and Capital Market Expert, respectively. In the Concentric report two figures did not appear once the document was formatted to the "pdf" version.

In an effort to conserve complete reprints Enbridge is sending the Board hard copies of only the two affected pages to be inserted into the three hard copies sent on September 8, 2009 to the Board Secretary's attention. For the RESS the complete document is being resubmitting so that the latest version can be accessed as one document for interested parties and the version sent on September 8, 2009 can be removed.

For interested parties who may wish to only reprint the pages affected they are: Concentric Report page 29 (showing Figure 3) – page 39 of complete pdf version; and Concentric Report B-10 (showing Figure 2) – page 94 of complete pdf version.

Please contact me if you have any questions.

Sincerely,

Lesley Austin

Lesley Austin
Regulatory Coordinator

cc: Fred Cass, Aird & Berlis (via email)

IN THE MATTER OF a Consultation by the Ontario Energy Board on the Cost of Capital.

WRITTEN COMMENTS OF ENBRIDGE GAS DISTRIBUTION INC.

On July 30, 2009, the Ontario Energy Board (the "Board") issued a notice in connection with the Board's review of its policy regarding the cost of capital. This notice was directed to a number of interested parties and stakeholders, including "All Gas Distributors". An Issues List was attached to the notice and interested stakeholders were invited to file written comments identifying their views and positions on the listed issues.

These are the written comments of Enbridge Gas Distribution Inc. ("Enbridge") filed in response to the invitation from the Board. Enbridge has also retained Concentric Energy Advisors ("Concentric") and Mr. Donald A. Carmichael to provide their views with respect to the issues raised in the Board's Issues List. Concentric and Mr. Carmichael have each prepared a report setting out their views and Enbridge is filing the two reports together with these written comments. Enbridge agrees with and adopts the responses to the listed issues by Concentric and Mr. Carmichael. Enbridge's comments that follow attempt to provide our utility's perspective on the cost of capital issues and the historic debate about utility returns.

The Fair Return Standard

The Board's Issues List for this consultation begins with a discussion of the current approach to the determination of appropriate returns for the utilities regulated by the Board. In these opening paragraphs of the Issues List, the Board states that the Fair Return Standard will be central to the consultation. Enbridge agrees with the Board's statement. The Fair Return Standard is the overarching guide – and, indeed, requirement - for any determination or review of appropriate returns for utilities regulated by the Board.

While this concept is well understood by parties to this proceeding, Enbridge takes the view that certain myths have crept into the Return on Equity ("ROE") debate which cloud the picture and make it especially difficult for the Board to meet the Fair Return Standard in its deliberations. We address some of these myths below.

Myth #1: The Fair Return Standard requires the Board to “balance the interests” of ratepayers and utility owners (shareholders).

The application of the Fair Return Standard does not involve a balancing of the interests of investors and ratepayers. The owners of a rate-regulated business are not able to set rates without the approval of the regulator. They rely on the regulator to protect their interests by fixing or approving rates that produce a fair and reasonable allowable return. There is a positive and absolute obligation on the regulator to apply the Fair Return Standard as set out in legal and regulatory precedent. Seeking to reduce otherwise fair returns so as to “balance” ratepayer/shareholder interests will inevitably fall short of meeting the Fair Return Standard.

Myth #2: The Fair Return Standard means there is a range of reasonable outcomes that can be established by the Board, so the Board should strive to set the Allowed return at the lowest acceptable point in the range of reasonable outcomes.

There is nothing in the Fair Return Standard that guides a regulator to set returns at the lowest possible level that can be achieved. The objective is to produce a fair return for investors who must rely on the regulator to protect their interests. To be sure, the Board has discretion on these matters; it is not a simple mechanical exercise. However the Board’s discretion should be applied on the basis of tested facts and analysis and not on the notion that the lowest possible number is acceptable and fair. Enbridge is of the view that the Concentric Report and the Carmichael Report provide the factual and analytic basis for the Board to set a fair and reasonable Allowed ROE. At Enbridge’s Allowed capital structure weighting (36% Common Equity), Concentric recommends, after considering all reasonable methodologies and facts, that the Allowed ROE should be 11% (Concentric report, page 10). Enbridge supports this recommendation.

Myth #3: Gas utilities continue to raise capital and make investments, so the existing allowed returns must be fair.

Some parties may believe that, as long as investors in a rate-regulated enterprise continue to raise capital and make investments, then the Fair Return Standard has been satisfied. Enbridge is a responsible owner of the largest natural gas distribution utility in Canada. Responsible utility owners invest the capital necessary to provide safe and reliable service to customers, both to honour the trust with their customers and to protect the value in their investments. This activity should not be turned to the disadvantage of utility investors by placing them in a “Regulatory Catch-22” situation in which the mere fact that a utility continues to invest for these purposes is given weight in the determination of what is a fair and reasonable Allowed return.

Myth #4: Utility owners will step forward to help Ontario meet its Clean Energy objectives, regardless of where the Board sets the Allowed returns.

The Board's allowed returns matter a great deal both to utilities and to their investors. In Ontario, as well as in other jurisdictions, there is a growing recognition of the need for major investments in energy infrastructure. Enbridge is supportive of the goals of the Government of Ontario with respect to energy infrastructure and is prepared to step forward and play its part in fulfilling those goals. Any reasonable investor contemplating such commitments in a rate-regulated environment, though, will look to see that there is a regulatory model in place in Ontario to support an expectation of fair returns. Put another way, potential Ontario investments must compete with other potential investments elsewhere in North America. The Board's Allowed ROE matters a great deal.

Myth #5: This process is about Electricity Utility returns and therefore is not relevant to Gas Utilities.

It is important to bear in mind that the Fair Return Standard applies equally to natural gas utilities and electricity utilities. When consideration is to be given to whether a particular methodology is producing fair returns for electricity utilities, it can hardly be appropriate to put off a similar review of the use of the methodology for gas utilities. The Fair Return Standard must be applied evenly to all utilities: investors are no less entitled to fair returns depending on whether they invest in electricity or gas utilities. Given the extent to which the Board has used a common approach for determining returns of electricity and gas utilities, fairness dictates that, if there is reason to extend the consideration of appropriate utility returns, the Board's review should encompass both gas and electricity utilities, equally, evenly and in the same timeframe.

Summary of Enbridge's Position

For the reasons elaborated on more fully in the reports from Concentric and Mr. Carmichael, Enbridge believes that the Board's formulaic approach is not producing fair returns for utility investors. Enbridge supports the recommendations made by Concentric with respect to changes to the Board's approach and asks the Board to establish processes to address the appropriateness of all Board allowed returns, as quickly as possible.

Outcome of this Consultation

In the event that the Board agrees, as a result of this process, that changes to current allowed ROEs and the going-forward ROE formula should be made to yield fair returns for utility investors, there are two linked and dependent outcomes to this proceeding that Enbridge will commit to. These are as follows:

1) While it was not the intention of Enbridge to give up the right to seek a reconsideration of Board-approved ROE during the term of the IR plan, Enbridge is prepared to leave the Allowed ROE contemplated in the IR Settlement unchanged during the annual rate adjustment process under IR (for years 2010,

2011, and 2012), and then to apply the outcomes of this proceeding (including any rebased or recalibrated Allowed ROE and the going-forward ROE formula) to Enbridge rates in the 2013 ("Rebasing") test year; and

2) The outcomes of this proceeding (including any rebased or recalibrated Allowed ROE and the going-forward ROE formula) will be applied to Enbridge's Earnings Sharing Mechanism ("ESM") calculations for the years 2010, 2011, and 2012. Given Enbridge's position that the existing ROE formula is not producing fair returns, Enbridge does not believe that use of the existing formula for the ESM calculation is appropriate. Instead, the ESM calculation should be based on the going-forward ROE formula - this is consistent with the wording of Enbridge's IR Settlement Agreement, which says that, for the purpose of the ESM, Enbridge shall calculate its earnings using the regulatory rules prescribed by the Board from time to time.

Conclusion

Enbridge supports the view that the current approach to determining returns and capital structure has led to an unreasonable and unfair situation for utility investors in Ontario. Enbridge congratulates the Board for commencing this review on its own initiative and asks that it continue the process, without unnecessary delay or interruption, until appropriate returns have been established for all of its regulated utilities.

ONTARIO ENERGY BOARD

2009 CONSULTATIVE PROCESS ON COST OF CAPITAL REVIEW

EB-2009-0084

ON BEHALF OF:

ENBRIDGE GAS DISTRIBUTION, INC.

CONCENTRIC ENERGY ADVISORS, INC.

James M. Coyne, Dr. J. Stephen Gaske, and Julie F. Lieberman

SEPTEMBER 8, 2009

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GLOSSARY OF TERMS

ATWACC	After-Tax Weighted-Average Cost of Capital
bps	Basis points
CAPM	Capital asset pricing model
Concentric	Concentric Energy Advisors, Inc.
DBRS	Dominion Bond Rating Service
DCF	Discounted cash flow
EBIT	Earnings Before Interest and Taxes
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization
Enbridge	Enbridge Gas Distribution
ERP	Equity Risk Premium
FERC	Federal Energy Regulatory Commission (U.S.)
FFO	Funds from operations
IRM	Incentive Regulatory Mechanism
IRR	Internal Rate of Return
LDC	Local distribution company
Moody's	Moody's Investor Services
MRP	Market Risk Premium
NEB	National Energy Board
NPV	Net Present Value
OEB or the Board	Ontario Energy Board
Ontario	Minister of Energy for the Province of Ontario
ROE	Rate of return on common equity
RRA	Regulatory Research Associates
S&P	Standard & Poor's
The Act	Energy Competition Act
TQM	Trans Québec & Maritimes Pipeline Inc.
Union	Union Gas Limited
U.S.	United States of America
WACC	Weighted-Average Cost of Capital

I. INTRODUCTION AND OVERVIEW

Enbridge Gas Distribution ("Enbridge" or the "Company") has retained Concentric Energy Advisors, Inc. ("Concentric") to assist the Company with responding to the issues raised in the Consultative Process on Cost of Capital Review initiated by the Ontario Energy Board ("OEB" or the "Board"). In this document, Concentric provides written comments and supporting analysis in response to the issues list distributed by the Board concerning a review of its policy regarding the cost of capital.

In its March 16, 2009 letter, the OEB 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. In addition to evaluating whether adjustments were warranted to the specified parameter values, the Board invited stakeholders to provide written comments on the following issues:

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?

A summary[1] of Concentric's written comments filed with the Board on April 17, 2009 on behalf of Enbridge follows:

> 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.
>
> 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.
>
> 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
> - Reduced earnings for dividends to shareholders
> - Negative impacts on debt coverage ratios and credit metrics
> - Inability to meet the fairness standard
>
> 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.
>
> 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.
>
> 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

1 For Concentric's full written comments, please see The Cost of Capital in Current Economic and Financial Market Conditions, Prepared For: Enbridge Gas Distribution, Comments in Response to Consultative Process, Board File EB-2009-0084, April 17, 2009.

> 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.

After reviewing the comments filed by interested stakeholders including Enbridge Gas Distribution, on June 18, 2009 the OEB issued a letter indicating that it was proceeding with a review of its policy regarding the cost of capital. In support of this decision, the Board wrote: "Nevertheless, the Board is satisfied that further examination of its policy regarding the cost of capital is warranted to ensure that, on a going forward basis, changing economic and financial conditions are accommodated if required." The Board stated that it would provide a list of issues that would form the basis of its review, and invited interested stakeholders to file written comments identifying their views and positions on the listed issues.

On July 30, 2009, the OEB asked interested stakeholders to address 19 specific questions related to its policy regarding the cost of capital and whether any changes should be made to the ROE Formula to better reflect changing economic and financial conditions. The Board indicated that it would continue to place primary reliance on the Equity Risk Premium approach. However, the Board indicated that it would review the application and the derivation of the current ERP approach to determine if it is sufficiently robust to guide the Board's discretion in applying the Fair Return Standard.

Finally, the Board scheduled a stakeholder conference from September 21 to 25, 2009 to provide a forum for discussion on the issues identified by the Board. Participants will be granted an opportunity to make presentations during the stakeholder conference.

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") 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).

II. EXECUTIVE SUMMARY

Concentric has determined that Ontario's currently allowed ROEs and capital structures do not meet an objective test of the Fair Return Standard. While it may be possible to rebase ROEs using the ERP method, Concentric recommends the utilization of multiple methods to determine ROE, and provides a detailed cost of capital analysis by sector to support this determination. The existing Formula tied to the Canadian Long Bond has not been an effective method for tracking equity costs.

In discussing the advantages and disadvantages of adopting a formula-based approach in its original Draft Guidelines, the Board observed: "A functional ROE formula should be capable of producing a rate of return that approximates the result which would have been produced through the traditional hearing process."[2] Concentric submits that the ROE formula has not met this test. In the appended analysis to this Report, we have demonstrated that alternative ROE estimation methods do not corroborate the results produced by the Formula. In addition, the allowed ROEs in

[2] Ontario Energy Board, Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities, March 1997, at 7.

Ontario do not allow the Province's regulated utilities to compete effectively with comparable North American utilities for equity capital.

The growing disparity between U.S. and Ontario allowed returns and the recent economic crisis has illuminated three major flaws in the Ontario Formula. First, it is our opinion that any formula, based solely on government bond yields, without any means of corroboration, is highly prone to error. In 1997, when the Ontario Formula was placed into effect, utility capital costs and government bond yields were perceived to move in lock step. Indeed, there is a strong historical relationship between the two. However, despite that strong historical relationship, government bonds can and do move independently from corporate utility capital costs and may sometimes move in opposite directions. In recent years, government bond yields have virtually derailed from utility bond yields, resulting in reduced returns dictated by the Ontario Formula when any measure of the fair return standard would indicate that utility equity returns should be increased.

The absence of a "corporate" capital cost component in the Ontario Formula, either by using the corporate bond yield or the spread between government and corporate bond yields, has allowed the Ontario Formula to move in an opposite direction to the actual cost of utility equity capital. One is hard pressed to imagine a viable scenario where corporate bond yields do not provide a more reliable basis for utility cost of capital than do government bond yields. Considering the recent economic crisis as a stress test for the Ontario Formula, the performance of the corporate bond yield has provided a more stable and reliable measure of the utility equity return than has the more volatile government bond yield.

Second, as discussed in Part VI of this Report, the coefficient in the current Formula in Ontario is mis-specified at 0.75, rendering it overly-sensitive to changes in interest rates. Historical relationships between bond yields and allowed returns in the U.S. reflect no greater than a 0.50 relationship. The cumulative effect of this mis-specification has contributed to the growing gap between U.S. and Ontario allowed returns. Note that in 1997, when the Ontario Formula was put into effect, U.S. allowed returns and Ontario allowed returns were in virtual parity. The overt sensitivity to changes in interest rates, coupled with the consistent decline in government bond yields since the Ontario Formula was placed in service, have been the most significant contributing factors to the disparity between U.S. and Ontario allowed returns.

Third and finally, the current Formula provides no means of corroboration for reasonableness. The absence of such corroborating measures has allowed the Ontario Formula to steadily diverge from U.S. returns, resulting in new efforts to restore fairness to equity allowances. According to Canadian and Ontario precedent, a fair return must meet each of three tests: financial integrity, capital attraction, and comparability. Nothing in the current Ontario Formula provides a check or any assurance that any one of those three tests has been met. As dictated by *Hope* and decades of Canadian regulatory practice, it is the end result that determines fairness and not the methodology that is controlling.[3] Any methodology employed to achieve those ends would be superior to the current Ontario Formula.

To achieve those ends, Concentric's recommendation is to rebase ROE and utilize a more effective index. Updated ROEs for the two major utility sectors are provided in Appendix F, based on a combination of CAPM and DCF estimates. The recommended formula incorporates 0.50 of the change in the Canadian A-rated 30-year Utility Bond as published by Bloomberg, weighted equally with an index based on recent litigated ROE decisions in North America (per Regulatory Research Associates "RRA" Rate Case Statistics). This methodology incorporates comparable returns in North American ROE awards, while maintaining an important tie to the Canadian financial markets and the prevailing corporate risk environment. We recommend this approach be applied annually in place of the current Ontario Formula for a period of 3-5 years. After this period, the formula should be revisited and if deemed necessary by stakeholders, rebased to recalibrate the starting point for returns in the succeeding 3-5 year period. This methodology meets the objective of regulatory expediency and is most likely, of the index-based solutions, to satisfy the fairness standard over time.

The Board's questions fall into eight general topics, which are addressed in this Report in the following sections:

IV. Application of Fair Return Standard (Questions 1, 2, and 3);
V. Choosing a Comparator Group (Questions 4, 5, and 6);
VI. Formula-based Approaches and the Equity Risk Premium (Questions 7, 8, 9, and 10);
VII. Choosing an Appropriate Base for the Equity Risk Premium (Questions 11 and 12);

[3] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

VIII. Calculating the Equity Risk Premium (Question 13);
IX. Adoption of a Dead Band and/or Trigger Mechanism (Questions 14 and 15);
X. Methods to Corroborate Results Produced by the Formula (Questions 16 and 17); and
XI. Using Financial Market Indicators to Test Reasonableness of Results (Questions 18 and 19).

An abbreviated summary of Concentric's response to each of the Board's questions is provided below. In order to fully document and support responses to the Board's questions, Concentric has provided supporting analysis and generic cost of capital estimates for Ontario's utilities, by sector, in attached appendices. Summaries of these analyses are provided in the body of the Report.

Question 1: *What method(s)/test(s) might the Board formally consider to determine whether the return on capital meets: (i) the comparable investment standard; (ii) the financial integrity standard; and (iii) the capital attraction standard?*

Comparable Investment Standard - There are three measures which are either observable or readily derived from financial market information: awarded ROEs for comparable companies, estimated ROEs for comparable companies, and actual ROEs earned by comparable companies.

Financial Integrity Standard - The minimum requirement of the standard is that the utility's return must be sufficient to meet its financial obligations and maintain sufficient credit metrics so that it may remain in good credit standing. Two primary indicators of credit quality that agencies focus on are interest coverage, expressed as a multiple of earnings before interest and taxes ("EBIT") or funds from operations ("FFO") in relation to debt interest payments.

Capital Attraction Standard - There are several tests that may be used to judge capital attraction. Sources that provide meaningful information on capital attraction for utilities include: equity analyst reports, credit rating reports, and direct market evidence.

Concentric presents several of these measures for Ontario's utilities in the report and appendices.

Question 2: *Is the current deemed capital structure appropriate? If not, what alternative(s) might the Board consider?*

No. The current deemed capital structure is not appropriate because it does not adequately recognize the relationship between the cost of common equity and the capital structure. Concentric recommends that the Board follow the NEB's lead in its recent TQM Decision and allow the regulated utility's management to choose an optimal capital structure within certain parameters because management is in the best position to assess the business and operating risks of the utility, and it would allow the utility to maintain financial flexibility to more quickly respond to changes in capital market conditions. The Board should rely on the Equity Cost Curve and the weighted average cost of capital curve to inform its judgment on this matter, but this can be done to set common ROE's and capital structure for each risk class (e.g., electric distributors) as long as they share common risk profiles.

Question 3: *Should the approach to setting cost of capital parameter values differ depending on whether a distributor finances its business through the capital markets or through government lending such as Infrastructure Ontario or through bank lending? If so, what would be the implications, if any, of doing so?*

No. Although the cost-of-capital parameter values may differ among utilities, the approach to setting cost of capital should be the same for all utilities. Other than flowing through actual debt costs or any differences in taxes in rates, there is no economic reason to treat government-owned or government-financed utilities any differently than privately-owned utilities when it comes to setting an allowed rate of return on rate base.

Question 4: *Does the analysis in the Concentric Report provide a reasonable foundation for satisfying the comparable investment standard?*

Not entirely. The Concentric Report provided sufficient basis to conclude that U.S. and Canadian utilities were indeed comparable enough to use as comparator or proxy companies, but further analysis is required to select only those utilities determined to be of similar risk for comparison to Ontario's utilities.

Question 5: *If not, what might the Board use as a comparator group?*

Concentric has performed a full proxy group selection for each of the sectors of Ontario's utilities. Please see Appendix C for the selection of the proxy group companies for Ontario's electric transmission and distribution, and natural gas distribution utilities.

Question 6: *Were the Board to only consider the use of Canadian utilities as a comparator group, is there an issue with circularity, given that the ROEs of these utilities are, and have been established by a mechanism similar to that currently used by the Board?*

Yes. With the exception of new NEB Group 1 pipelines, Canadian utilities' authorized returns largely fail to provide meaningful information for comparison due to the circularity stemming from the widespread use of the formulaic ROE model across Canada. Meaningful DCF and CAPM analyses can be done on publicly-traded Canadian companies that are of comparable risk. However, there are few such companies.

Question 7: *Should the ERP approach be reset given that when the formula was first established the reference bond rate was 8.75%?*

Yes, assuming the Board decides to continue to use the ERP approach. The misspecification of the sensitivity is one reason for the systematic understatement of utility ROEs and equity risk premiums over the past decade. Benchmarking the Formula-produced return using alternative measures of equity costs, with appropriate adjustments, is essential to ensuring a fair return.

Question 8: *Should the ERP approach be reset on a regular basis (e.g., every 4 or 5 years) to mitigate the issues described in the 1997 Compendium?*

Predetermined check-in periods should be maintained (every 3 – 5 years) to allow all parties the option (but not the requirement) to reset the Formula as well as providing a routine check on the performance of the Formula and a forum for suggesting improvements or enhancements to the Formula.

Question 9: *How might the Board address the potential issues arising from the application of the current methodology as a single, point-in-time calculation?*

ROEs determined through the appropriate methods are forward looking. Markets change continually. The best the Board could do, and should attempt to do, is to make its decisions based on the market conditions that exist at the time the Board establishes the rate of return and then monitor the results.

Question 10: *How should the Board establish the initial ROE for the purposes of resetting the methodology?*

Multiple approaches for determining ROE provide greater assurance that the end result will be just and reasonable, as conditions that may bias results could be detected or mitigated by considering alternative results. Primary reliance should be placed on the CAPM and DCF results, with corroboration provided by reviewing a risk premium approach, comparable earnings of low risk industrials and allowed returns in other jurisdictions. Concentric has provided a complete cost of capital study for the Ontario utilities, using the DCF and CAPM as our primary analyses and the ERP and Comparable Returns as a means of benchmarking the reasonableness of the results of our primary analyses. A summary of those results by sector, adjusted for differences in leverage between the proxy group and the Ontario utilities, is provided below:

Table 1: Leverage Adjusted ROEs and Capital Structures for Ontario Utilities

SUMMARY OF RECOMMENDED COMMON EQUITY RATIOS AND APPLICABLE ROES							
	COMMON EQUITY PERCENTAGE IN BOOK CAPITAL STRUCTURE						
	34%	36%	38%	40%	42%	44%	46%
Gas Distribution	11.3%	11.0%	10.7%	10.5%	10.2%	10.0%	9.8%
Electric Transmission and Distribution	11.2%	10.9%	10.6%	10.3%	10.1%	9.9%	9.7%

Question 11: *Is the government (of Canada) bond yield the appropriate base upon which to begin the return on equity calculation?*

Government bond yields in themselves are not an appropriate base for setting ROE; multiple methodologies must be employed and afforded appropriate weight to arrive at an ROE that meets the fair return standard and is indicative of utility equity costs. For indexing purposes, corporate bond yields are a superior measure that would more accurately track utility equity costs.

Question 12: *What is the relationship between corporate bond yields and the corporate cost of equity? Is this relationship sustainable?*

Historically, corporate bond yields and corporate costs of equity have enjoyed a strong historical relationship and reflect the market's perspective on corporate credit risk, which is an important component that has been missing from the existing Formula. Concentric finds that the corporate bond yield provides a more suitable basis for the ROE Formula than the government bond yield.

Our analysis has indicated that the sensitivity of the corporate bond to allowed returns is roughly from 0.45 – 0.50. Monitoring and periodic reviews are necessary to ensure that these relationships continue in the future.

Question 13: *Does the current approach used by the Board to calculate the ERP remain appropriate? If not, how should the ERP be calculated?*

No, the Board's current approach to calculating the equity risk premium ("ERP") is not appropriate because it results in an ERP that is substantially lower than any of the corroborating benchmarks. The Board should not limit itself to one specific method of calculating an equity risk premium; rather, it should consider the results produced by multiple approaches in order to generate a range of reasonable results from which it may select an appropriate ERP.

Question 14: *Should the Board adopt a dead band? If so, what should the range of the dead band be?*

Though Concentric has not recommended a deadband in its formula, we accept that a deadband has the benefit of regulatory efficiency, and is appropriate when regulatory expediency can be optimized without sacrificing a fair return. Deadbands may also serve a useful role when performance based rates ("PBR") are coupled with the base return.

Question 15: *Should the Board adopt trigger mechanism(s). If so, how often should the Board review the methodology?*

If the Board continues with a formula, and accepts Concentric's recommended index along with both an annual monitoring process and 3-5 year formal review of the methodology and ROE results, a trigger mechanism is not necessary. If the existing formula tied to government bond yields is used we would strongly urge a trigger mechanism tied to corporate bonds and awards from litigated jurisdictions.

Question 16: *What is the appropriate test(s) to ensure the FRS is met (e.g. corroborating results for reasonableness relative to other benchmarks or through other methods)?*

In order to definitively determine whether the fair return standard is being met, a cost of capital study is required, such as that presented in Appendix F. Recognizing that the Board desires an approach that is efficient to administer, it is relatively straightforward for Staff to update DCF and CAPM studies using readily available information. If the Formula return deviates significantly from the average results of the DCF and CAPM studies for a specified period of time, the Formula should be re-opened and a re-basing of the Formula should be considered. Similarly, if a utility has difficulty raising capital on reasonable terms, the Board should consider that special circumstances exist that would dictate either deviating from the Formula or re-basing the Formula as necessary.

Question 17: *What information might the Board need to definitively determine that market conditions are having an effect on the variables used by the Board's cost of capital methodology?*

In addition to the cost of capital monitoring outlined in response to Question 16, comparable returns analysis, changes in the level of corporate debt costs, as well as the level of yield spreads and the comments of professional equity analysts should corroborate or suggest that the Board's Formula does, or does not, continue to reflect the cost of common equity capital for Ontario electric utilities or gas utilities.

Question 18: *Should the Board consider monitoring indicators like these on an on-going basis to test the reasonableness of the results of its cost of capital methodology?*

Yes. The Board should remain an informed participant and apprised of trends in capital markets through practical routine monitoring of those factors mentioned in our responses to Questions 16 and 17 above.

Question 19: *What other key metrics used by financial market participants to determine whether financial markets conditions are or are not "normal" might the Board consider?*

Some basic indicators that might provide the Board with an early warning signal that it should conduct a more thorough DCF or CAPM analysis would include: changing credit spreads between corporate and government bonds, changes in equity market volatility indices, credit rating changes for Ontario utilities, divergence between Canadian and U.S. debt and equity market indices, and shifts in price/earnings ratios and dividend yields for publicly traded utilities.

III. BACKGROUND

In Ontario, the ROE Formula was first established for natural gas distribution utilities in 1997 with the OEB's "Draft Guidelines on A Formula-Based Return on Common Equity for Regulated Utilities" ("Draft Guidelines"). 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.[4]

In 1997, the OEB established the benchmark ROE by taking the forecast yield for long-term Government of Canada bonds and adding an estimated risk premium to account for utility risk relative to long-term Government of Canada bonds. The equity risk premium test was used to determine the appropriate risk premium. Once established, the benchmark ROE has been adjusted annually using a formula. The change in the forecast yield for long-term Government of Canada bonds is multiplied by a factor of 0.75 to determine the adjustment to the allowed ROE. This adjustment factor is then added to the utility's previous test year ROE and the sum is rounded to two decimal points to produce the new ROE.

The Board concluded that it would review the rate of return formula as conditions arise that may call into question its validity, such as significant shift in business risk or market conditions. Parties to a proceeding may ask the Board to review the Formula when they feel it is appropriate or the Board may do so on its own initiative. In either case, it is the Board's decision as to the time for a review. The Board may request the presentation of other tests or require some weighting for other tests in the Formula should the Board want to assure itself that the ERP formula approach does not lead to perverse results and is directionally in line with other market indicators.

The current allowed ROE for Enbridge Gas Distribution is 8.39 percent. Enbridge is also subject to the provisions of an incentive regulation plan through 2012, under which the Company is allowed to retain 100 percent of earnings for up to 100 basis points above the annually calculated Ontario Formula ROE. Earnings above that level are shared 50/50 with customers. In general, the Board

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4 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.

has not adopted earnings sharing mechanisms for electric utilities. Allowed returns and equity ratios for Ontario's largest gas and electric utilities, are presented in Table 2.

Table 2: Authorized Returns and Equity Ratios for Ontario's Largest Utilities

	2009 Authorized ROE	2008 Authorized ROE	2009 Authorized Equity Ratio
Enersource Hydro Mississauga	8.57%	8.57%	40.00%
Horizon Utilities Corporation	8.57%	8.57%	40.00%
Hydro One Distribution	8.57%	8.57%	40.00%
Hydro Ottawa Limited	8.57%	8.57%	40.00%
PowerStream Inc.	8.01%	9.00%	40.00%
Toronto Hydro-Electric System Limited	8.01%	8.57%	40.00%
Veridian Connections Inc.	9.00%	9.00%	40.00%
Enbridge Gas Distribution Inc.	8.39%	8.39%	36.00%
Union Gas Limited	8.54%	8.54%	36.00%

Note: Enersource, Horizon, Hydro One, Hydro Ottawa and Veridian did not rebase for 2009 and Veridian also did not rebase in 2008. Hydro One Transmission's approved return was 8.35% for 2008 and 8.01% for 2009.

In its 1997 Draft Guidelines, the OEB expressed its policy on capital structure as follows: "The Board believes that the capital structures should be reviewed only when there is a significant change in financial, business or corporate fundamentals."[5] In discussing the steps necessary to implement the new ROE formula, the Board further clarified its approach to capital structure: "The Board's guidelines also assume that the base capital structure will remain relatively constant over time and that a full reassessment of Consumers Gas' capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk."[6]

In 2006, the Board revised it policy on capital structure for electric distributors as follows: "The Board will deem a single capital structure for all distributors for rate-making purposes . . . The Board has determined that a split of 60% debt and 40% equity is appropriate for all distributors." Prior to this revision, the Board had allowed for different capital structures for electric distributors based on their size (in terms of operations, assets, and revenue base) and the geographic size and isolation of particular distributor service areas. The Board abandoned any distinction based on size noting that

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5 Ontario Energy Board, Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities, March 1997, at 4.

6 Ibid, at 30. Consumers Gas was the first to have the ROE Formula applied in Ontario.

there had been considerable restructuring in the industry through mergers and acquisitions from 1999 through 2006, which reduced the number of distributors from over 300 to less than 90.[7]

Prior to 2007, the equity component of electricity distributors' capital structures ranged from 35% to 50% based on each utility's rate base. Beginning in 2007, the Board deemed a 40% common equity component for all electricity distributors. For natural gas distributors, the Board increased the equity component from 35% to 36% for the 2007 rate year.

Concentric notes that the OEB understood that there were potential disadvantages associated with formula-based ROE mechanisms. In its 1997 Draft Guidelines, the OEB wrote:

> There are a number of potential disadvantages of formula-based ROE mechanisms; however, if adequately controlled for, they can be minimized. Establishing the initial parameters of the generic formula (as implied in the initial ROE and the subsequent adjustment mechanism) will have a profound influence on the potential success or failure of the process. Over time these parameters and adjustment factors will have a cumulative or compounding effect on the results of the formulaic ROE mechanism. The use of an inappropriate initial ROE will either inflate or understate subsequent rate determinations. A second consideration which must be dealt with is that a formula ROE generally relies predominately (sic) on the equity risk premium method to the exclusion of other methods and, hence, sacrifices the unique contributions of these other approaches. A further potential challenge in setting a formula-based ROE is adjusting for the impact of timing differences for utilities with different year-ends. Finally, a move to formula-based ROEs may restrict a regulator's ability to make discretionary adjustments to a utility's return for the purpose of creating incentives for particular behaviours or sending signals to the marketplace.[8]

Based on the deviation of the formula-based returns from other common ROE benchmarks, including allowed returns for utilities in other jurisdictions, it appears that the OEB's initial reservations about an ROE formula were well-founded. Many of the disadvantages anticipated by the Board have, in fact, come to fruition. This proceeding affords the OEB an opportunity to re-examine whether a formula-based approach satisfies the Fair Return Standard in Ontario. Concentric would urge the Board to consider the evidence presented in this report and others,

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7 Ontario Energy Board. *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors.* December 20, 2006, at 5-6.

8 Ontario Energy Board, Draft Guidelines, at 7.

demonstrating that the current Ontario Formula, which relies on government bond yields and an equity risk premium, is not appropriate for establishing a fair return for Ontario's regulated utilities.

IV. APPLICATION OF THE FAIR RETURN STANDARD

Question 1: What method(s)/test(s) might the Board formally consider to determine whether the return on capital meets: (i) the comparable investment standard; (ii) the financial integrity standard; and (iii) the capital attraction standard?

Response

As noted by the Board, and consistent with the Decision in *Northwestern Utilities vs. City of Edmonton, (*1929)[9], three tests are required in determining whether the fair return standard has been met, the "comparable investment" test, the "capital attraction" test, and the "financial integrity" test. Consistent with the widely accepted *Hope (*1944) standard in both the U.S. and Canada[10] the Board should ultimately consider the end result of its allowed returns in making this determination. The "comparable investment" test addresses the opportunity cost associated with equity capital and allows the utility the opportunity to earn a return sufficient to compete for equity capital among comparable risk companies. The capital attraction and financial integrity tests reflect the minimum standards for establishing a fair return and are related to ensuring the financial soundness of the utility with the ability to attract the necessary capital to maintain and expand its system. Furthermore, the utility must be able to attract capital on reasonable terms as a stand-alone entity, regardless of the strength or weakness of its parent holding company. The authorized return must satisfy all three tests to meet the standards for a fair return in Ontario.

i. Comparable Investment Standard

This standard is based on the opportunity cost of capital principle. Investors in Ontario's utilities forego the opportunity to invest that same capital in alternatives, so they should be compensated so

9 Supreme Court of Canada, *NORTHWESTERN UTILITIES LTD. VS. THE CITY OF EDMONTON* (1929 SCR192).

10 Cost of Capital, Dr. Bill Cannon, Presentation at CAMPUT's 2009 Energy Regulation Conference, July 3, 2009, p. 17.

that their return on equity is at least equal to the return that could have been earned on an alternative investment of comparable risk. The NEB defines the standard as follows:[11]

> Comparable Investment Requirement: The aspect of the Fair Return Standard that requires that the return of a regulated utility be comparable to the return available from the application of the invested capital to other enterprises of like risk.

Because no two companies are identical in terms of operating and financial characteristics, regulators must make a reasoned judgment to weigh the impact of differences when making comparisons between companies that are fundamentally similar. All too often, companies are ruled as non-comparable due to their differences rather than factoring those differences into the comparison. The standard of "comparable investments" does not require that the investments be "identical", otherwise the standard would be impossible to meet.

Concentric believes that the regulator must look to equity returns from comparable businesses, just as an investor would. This may be done through examination of allowed returns, actual equity returns, or those expected by investors. There are three measures which are either observable or readily derived from financial market information.

1. **Awarded ROEs for comparable companies** – Most Canadian jurisdictions rely on the Formula which is the very subject of the Board's inquiry as well as investigations in BC, Alberta, and Quebec, and rejection in the case of the NEB for TQM. The Board must therefore look to non-formula based ROE awards to establish comparability, otherwise the exercise is completely circular. Concentric believes that ROE awards for North American gas and electric utilities, (U.S. utilities augmented by Canadian litigated ROEs when they occur), provide the best possible objective source for this comparison, and we present this comparison.
2. **Estimated ROEs for comparable companies** – the very purpose of cost of capital estimation is to determine required investor returns for a given investment. The CAPM, DCF and ERP methods are relied upon to produce these estimates. Financial and regulatory analysts typically rely on the DCF and CAPM models, or a combination of the two, applied to a group of proxy companies with similar business profiles. Concentric presents the results of its analysis based on these methods.

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11 NEB Reasons for Decision, RH-1-2008, TransQuebec and Maritimes Pipelines, Inc., Cost of Capital for 2007 and 2008, March 2009, p. vii.

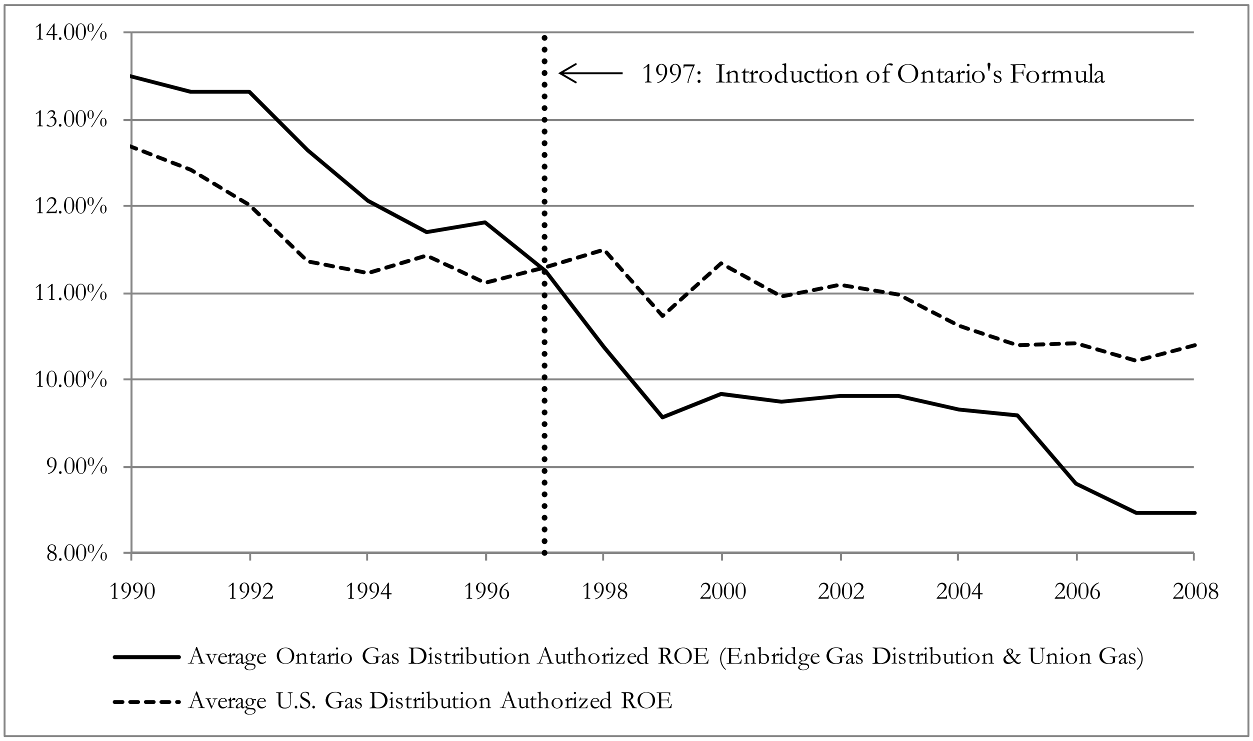
3. **Actual ROEs for comparable companies** – Data on "earned" or "actual" ROEs at the utility level are not uniformly reported, but this information can be helpful in understanding investor requirements for equity returns. In addition, it is possible to specify a group of low risk companies to serve as proxies for utility returns in order to determine the level of returns earned by companies with comparable risks.

As indicated subsequently in this report, the current allowed equity return produced by the Ontario Formula for 2009 in Ontario is 8.01% (based on the January 2009 Consensus Forecast), which is well below the benchmark return resulting from Concentric's ROE analyses. ROE awards for Ontario utilities are below those of the comparable U.S. proxy groups whose estimated ROEs ranged from 9.41 percent to 10.95 percent and are below the results of the ROE analyses performed on the group of Canadian proxy companies, informed by multiple methodologies, which resulted in an ROE estimate of 9.77 percent. These analyses indicate that the Ontario authorized returns are deficient in meeting the comparable investment standard by a magnitude ranging from 140 to 294 basis points.

Concentric has established the comparability between U.S. and Canadian utilities by analyzing regulatory, financial and operational characteristics of the Ontario utilities compared to the proxy group utilities. The results of that analysis are discussed in our responses to Questions 4 and 5, but generally lead us to conclude that though there are differences in risks between the utilities, they are largely offsetting and do not explain the growing disparity in allowed returns. Rather, the more likely explanation has been the adoption of the ROE Formula in Ontario and what we would submit were unanticipated consequences.

As the Figure below illustrates, U.S. and Ontario authorized returns were in virtual parity when the Formula was first implemented in Ontario in 1997, and prior to that date exceeded U.S. returns. Since then, a growing gap has occurred which we would characterize as a "fairness deficit" in relation to the comparability standard.

Figure 1: Historical Authorized Returns – U.S. vs. Ontario (Gas Distribution)



ii. Financial Integrity Standard

The NEB defines the financial integrity standard as follows:[12]

> Financial Integrity Requirement: The aspect of the Fair Return Standard that requires that the return of a regulated utility enable the financial integrity of the regulated enterprise to be maintained.

There are many factors to consider when assessing whether the financial integrity standard has been met. The *minimum requirement* of the standard is that the utility's return must be sufficient to meet its financial obligations and maintain sufficient credit metrics so that it may remain in good credit standing. One could look to the utility's credit rating to verify that this minimal component of the three-pronged standard has been met. For most Canadian electric and gas utilities, an A level credit rating is considered adequate to provide favorable access to credit markets under a variety of market circumstances. All too often, regulators look only as far as the utility credit ratings for evidence that the fair return standard has been met. However, the credit rating measures only the utility's ability to meet the minimum financial integrity standard, i.e. addressing only the risk of bond default. The

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12 NEB, RH-1-2008, op. cit., p. viii.

credit rating has little to no implication on the residual risk to the shareholder in assessing its ability to earn its required return once debt holders have been paid.

As shown on Table 3, the returns generated by the generic allowed ROE in Canada and in Ontario, in many cases, do not provide sufficient financial metrics to satisfy the ratings criteria for an A-grade credit rating. Thus the return is deficient in meeting the minimum standards for financial integrity. The ratings agencies in Canada have allowed the Canadian utilities a higher degree of leverage than would generally be required of an investment grade utility company. Though the ratings agencies may be satisfied with the utility's ability to meet its debt obligations, the shareholders are left uncompensated for the increased risk associated with higher leverage.

Table 3 presents the financial metrics of Ontario's largest gas and electric utilities. This profile illustrates that the credit ratings of the electric utilities are all at the A level, generally considered the standard for Canadian utilities. The gas company ratings are lower, at A- and BBB+ on an S&P basis. Two primary indicators of credit quality that agencies focus on are interest coverage, expressed as a multiple of earnings before interest and taxes ("EBIT") or funds from operations ("FFO") in relation to debt interest payments. These cover a fairly broad range for Ontario's utilities. As a general principle, rating agencies look for debt/capital (regulated assets) in the 45-60 percent range[13], EBIT coverage in the 2x – 4x range[14] and FFO coverage in the 4.5x – 6.0x range[15] for regulated utilities to earn an A level credit rating. These are metrics that the Board can monitor, but it must be careful to realize that these ratings are for debt only and therefore represent a minimum standard of financial integrity.

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13 Rating Methodology, *Moody's Global Infrastructure Finance - Regulated Electric and Gas Utilities (*August 2009) at 17.
14 Rating Methodology, *Moody's Global Infrastructure Finance – Regulated Electric and Gas Networks* (August 2009) at 20.
15 Rating Methodology, *Moody's Global Infrastructure Finance - Regulated Electric and Gas Utilities (*August 2009) at 17.

Table 3: Financial and Credit Metrics for Ontario's Largest Utilities

Utility	S&P Credit Rating	DBRS Credit Rating	Moody's Credit Rating	EBIT Interest Coverage Ratio	FFO Interest Coverage Ratio	Deemed Equity Ratio
Enersource Hydro Mississauga Inc.	NR	A	NR	2.36	3.60	40.00%
Horizon Utilities Corporation	NR	NR	NR	3.23	5.05	40.00%
Hydro One Inc. (Distribution)	A+	A	Aa3	2.50	4.21	40.00%
Hydro One Inc. (Transmission)	A+	A	Aa3	3.29	4.53	40.00%
Hydro Ottawa Limited	A	A	NR	3.54	5.36	40.00%
PowerStream Inc.	NR	A	NR	2.58	4.08	40.00%
Toronto Hydro Electric System	A	A	NR	2.05	4.11	40.00%
Veridian Connections Inc.	NR	A	NR	2.03	4.41	40.00%
Enbridge Gas Distribution, Inc.	A-	A	NR	2.19	3.32	36.00%
Union Gas Limited	BBB+	A	NR	2.47	3.47	36.00%
CREDIT RATING STANDARD			**A**	**2.00–4.00**	**4.50–6.00**	**40.00 -55.00**

Circled items do not meet credit rating standard

Sources: 2008 Annual Reports and Bloomberg

FFO = net income + interest expense + depreciation and amortization expense + deferred income tax expense

The impact of the highly leveraged capital structure on the financial condition of the utilities has a pronounced effect on coverage ratios and debt/capital ratios, resulting in ratios that are insufficient in some cases or on the cusp of being sufficient to justify an A bond rating.

iii. Capital Attraction Standard

The NEB defines the capital attraction standard as follows:[16]

> Capital Attraction Requirement: The aspect of the Fair Return Standard that requires that the return of a regulated utility permit incremental capital to be attracted to the enterprise on reasonable terms and conditions.

There are several tests that may be used to judge capital attraction, but "reasonable terms and conditions" requires a more subjective assessment. It is important to note the emphasis on "incremental capital" in the NEB's definition. Evidence of sunk capital is not evidence of the ability to raise incremental capital. As has been witnessed over the past 18 months, creditworthy companies have struggled to raise incremental capital on reasonable terms during the economic and

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16 NEB, RH-1-2008, Op. cit., p. vii.

financial downturn. Sources that provide meaningful information on capital attraction for utilities include:

1. **Equity analyst reports** – the major banks and independent equity analysts provide opinions on the overall attractiveness of a utility's (or its holding company's) common stock. The major utilities are generally covered by equity analysts, but in Ontario, only Enbridge, Union and Fortis have publicly traded stocks (at the parent company level), limiting the availability of this source for the sector. While these reports may not be specific to the regulated utility (if under a holding company), they provide an informed view of the company's attractiveness compared to their peers. Positive investment reports suggest the ability to attract incremental investment capital; conversely, negative reports may portend loss of liquidity and increasing equity cost. In viewing equity reports, one must use caution to not let holding company affiliates mask weakness (or strength) of the underlying utility.
2. **Credit rating reports** – the major credit rating agencies, namely S&P, DBRS and Moody's regularly publish credit rating reports on covered utilities. These reports provide a view into the agency's perspective on the utility's (or its holding company's) credit quality, with a focus on debt issuance. Credit watches or downgrades are a cause for concern in maintaining credit quality.
3. **Direct market evidence** – the ability of the utility to issue debt and equity on terms comparable to their similarly situated and rated peers.

A fair return allows access to both equity and debt capital on reasonable terms. The return built into rates should be adequate to yield revenues that will cover all legitimate expenses, plus a return on investment sufficient to maintain sound corporate credit and attract new capital.[17] Canadian utilities are often owned by diversified holding companies that are charged with the responsibility of attracting equity capital at the holding company level. Parent company returns are often well above those allowed for regulated utilities in Ontario and thereby imply that the ability of the utility to attract new equity capital is aided by the diversification and higher returns of its parent. As described in the Capital Budgeting - Appendix A, subsidiaries must compete for capital at the holding company level. Lack of a fair return on the utility capital will ultimately lead to either underfunded utility subsidiaries or inadequate investment in growth.

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17 Bonbright, Danielsen and Kamerschen, Principles of Public Utility Rates, at 610.

iv. Additional Evidence that Current Returns do not Satisfy the Fair Return Standard

There is evidence that equity investors and analysts find allowed returns in Canada and Ontario to be inadequate. A market research bulletin by RBC Capital Markets indicates that investors should be concerned about the low level of returns throughout Canada where the Formula has been implemented, especially in the current global credit crunch. They state:[18]

> Although the automatic adjustment formulas that annually calculate allowed returns on equity (ROE) for many pipelines and utilities in Canada have been good for transparency, developments over the past year in the equity and credit markets leave us wondering if the ROE formulas are broken. Despite investor concerns about access to credit, let alone higher overall corporate borrowing costs, in addition to higher equity risk premiums, these formulas appear set to further reduce the allowed ROEs for 2009 based on the inputs that the formulas use to calculate the annual ROEs….
>
> …While challenges to both the NEB and provincial ROE formulas have only been met with limited success, we believe that there could be support for higher allowed ROEs based on a decline in the formula return despite significant weakening in the debt and equity capital markets.

RBC Capital Markets' comments goes on to steer investors towards diversified pipeline stocks where capital is being diverted to higher ROE projects, as indicated below:

> All of the corporate names in our energy infrastructure coverage universe should have some degree of negative earnings impact from lower allowed ROEs, although the estimated impact to earnings is relatively modest across the group. Nevertheless, we believe that the negative impact of lower allowed ROEs on the companies with regulated utility assets provides additional support for our recommendation that investors overweight the pipeline stocks (Enbridge and TransCanada), which are directing a majority of their capital towards higher ROE projects (generally in the 10% to 15% range).

In a follow-up report, RBC goes on to state:

> We published a Research Comment on January 16, 2009, that examines the direction of the allowed ROE formulas in Canada and makes stock recommendations based on our outlook. The comment follows up on our 2009 ROE preview published last October, with regulators over the past month or so confirming that 2009 ROEs would decline by about 15 basis points. Against the backdrop of higher Energy Infrastructure long bond yields and rising equity risk premiums, we believe the ROE formulas are broken. Using current data as a preview for 2010 ROEs, we calculate

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18 RBC Capital Markets, Equity Research, ROE Outlook for 2009, October 24, 2008.

that ROEs could further decline by another 67 basis points. While regulators are currently examining the issue, historically they have been reluctant to change the formula, and we believe that the potentially meaningful decline for ROEs set by formulas in 2010 should cause investors to seek out companies with low exposure to the formulas.[19]

Upon reversal of the Formula in the NEB's TQM decision, BMO Capital Markets opined:

> We applaud the NEB for acknowledging that the RH-2-94 formula is no longer applicable given the changes in business risk, financial markets and economic conditions. In particular, the globalization of financial markets made it difficult for Canadian operators to compete for capital with such low ROE.[20]

Further punctuating the recent impacts of capital markets and the Formula, Scotia Capital denotes:

> The turmoil in financial markets over the last 18 months has had a material knock-on effect on a sector typically seen as a safe haven from adverse equity market volatility and valuations. Energy utilities across Canada have seen their regulated returns on equity squeezed by falling Government of Canada bond yields, even as the real-world cost of equity capital has risen dramatically.[21]

On the impact of declining ROE's on the financial health of formula-based utilities, DBRS concludes:

> The negative impact of declining levels of approved ROEs on credit metrics is illustrated in the generic example below, wherein a 2% decline in approved ROE translates into an approximate 30 bps reduction in EBITDA-to-interest and EBIT-to-interest, and a 130 bps reduction in cash flow-to-debt, all other parameters remaining equal.

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19 RBC Capital Markets, Equity Research, Power & Pipelines, January 16, 2009.
20 BMO Capital Markets, Corporate Debt – Pipelines & Utilities, March 23, 2009.
21 Scotia Capital, Capital Points, April 24, 2009.

Table 4: Impact on a Theoretical Utility of Declining Approved ROE*

Rate Base ($MM)	1,000	1,000	1,000
Debt Component	60%	60,0%	60,0%
Cost of Debt	6.5%	6.5%	6.5%
Equity Component	40%	40%	40%
Approved ROE	10%	9%	8%
Depreciation Rate	4%	4%	4%
Tax Rate	35%	35%	35%
EBITDA/Interest	3.6x	3.4x	3.3x
EBIT/Interest	2.6x	2.4x	2.3x
Cash Flow/Debt	13.3%	12.7%	12%
* Simplified example; all else remains the same, only variable is Approved ROE			

> Overall, we note that an improvement to a regulated entity's ROE and/or equity thickness would be viewed positively in the context of its financial risk profile. However, as approved ROEs have declined in past years, ratings (to this point) have generally not been directly negatively impacted. Therefore any future increase in a pipeline or utility's approved ROE or equity thickness would in itself likely not result in positive rating actions unless the improvement was so significant as to be viewed as a material reduction in financial risk. It is more likely that ROE or equity thickness improvements would be viewed as being supportive of an entity's current ratings.[22]

To summarize, equity investors and analysts have broadly proclaimed that the Formula does not produce adequate returns. In some cases, subsidiary utilities may not be attracting incremental equity capital on their own merit. This is contrary to the stand-alone principle, which is fundamental to regulation in Ontario. Because utility affiliates in the unregulated sector are earning higher returns, utilities are drawing on parent company support for capital to withstand the low level of allowed regulated returns. Over time, however, the utility is at a disadvantage when it comes to competing internally for incremental capital in these diversified companies, and at an international disadvantage when seeking to attract equity from North American investors who can readily seek higher returns in the U.S.

The same can be said for Ontario's government and municipally owned electric utilities. Sub-standard returns essentially subsidize the utility ratepayers at the expense of taxpayers. When the

[22] DBRS Canada Newsletter, Volume 1, Issue 4, May 6, 2009.

taxpayer and utility customer is the same, the subsidy may not be problematic, but it does not send proper price signals and creates a barrier to the competitive environment in Ontario.

Question 2: Is the current deemed capital structure appropriate? If not, what alternative(s) might the Board consider?

Response

The current deemed capital structure is not appropriate because it does not adequately recognize the relationship between the cost of common equity and the capital structure. The Board noted this important relationship in its 1997 Draft ROE Guidelines when it wrote: "The principle behind establishing the rate of return on a utility's debt and equity capital is that it should equal the corresponding rate of return that a comparable firm with a similar capital structure, facing similar aggregate business and financial risks, would expect to experience."[23] Having acknowledged that allowed return and capital structure are interdependent, it is surprising as illustrated in Table 2, previously, that the Board has deemed like ROEs and capital structures for all of the electric distributors. This "one-size-fits-all" approach fails to recognize that every regulated utility in Ontario is not exposed to the same business and operating risks. If capital structure is held constant for regulatory purposes, then there should be wider variations in allowed ROE to account for differences in risk profiles.

Concentric recommends that the Board follow the NEB's lead in its recent TQM Decision and allow the regulated utility's management to choose an optimal capital structure within certain parameters because management is in the best position to assess the business and operating risks of the utility, and it would allow the utility to maintain financial flexibility to more quickly respond to changes in capital market conditions.

> The Board's decision to grant an aggregate return on capital without specifying capital structure has the result of transferring to the pipeline company the decision to determine its optimal capital structure and choose specific financial instruments without regulatory oversight. The freedom for a company to choose its optimal capital structure is consistent with the Board's philosophy of regulating pipeline companies on a goal-oriented basis. Exercise of that freedom does not, in the

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[23] Ontario Energy Board, Draft Guidelines, at 2 and 27.

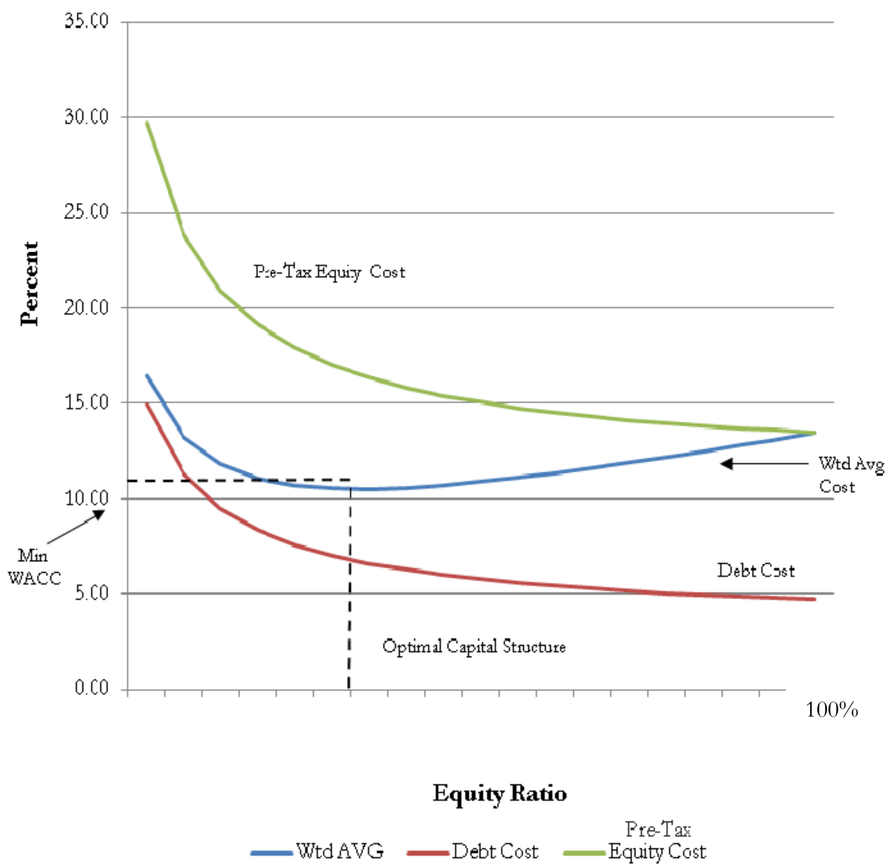
> Board's view result in a wealth transfer, and is supported by the longstanding stand-alone principle.[24]

Alternatively, if the Board wishes to retain authority over the process of deeming a capital structure, it should consider whether the combination of allowed ROE and deemed equity ratio for a particular utility satisfies the Fair Return Standard. Concentric demonstrates in the attached Appendix B: *Capital Structure - Theory and Application* that this question can be answered by examining where the overall rate of return falls on the weighted average cost of capital curve that is described more fully in that explanation, and illustrated in Figure 2.

In summary, capital structure theory suggests that a company's capital structure and the return on equity are interdependent. The Board should not establish an allowed ROE without expressly considering that return in light of the financial risks associated with the utility's capital structure. Further, the Board should not rely on a bond rating analysis for purposes of determining whether the allowed ROE is adequate, because the return that might be sufficient to satisfy bond holders is not the same as the return required by equity holders. Therefore, the Board should rely on the Equity Cost Curve and the weighted average cost of capital curve to inform its judgment on this matter.

[24] National Energy Board, Reasons for Decision, Trans Quebec & Maritimes Pipelines, Inc., RH-1-2008, March 19, 2009, at 81.

Figure 2: Cost of Capital Curves According to Finance Theory

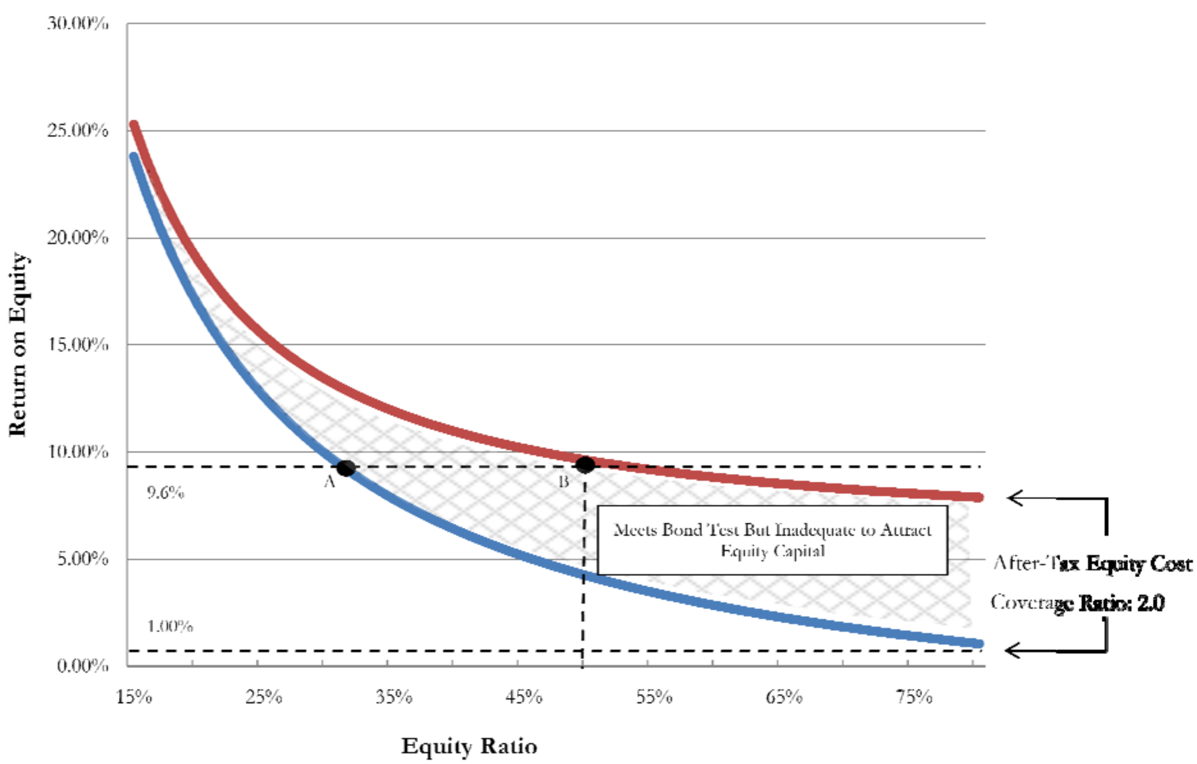


Determination of the cost of common equity at any point in time is too complex to be accomplished by merely tweaking allowed ROE or equity ratio for differences in risk. Instead, the observed ROEs in any given cost of capital study correspond to particular common equity ratios, and represent a specific risk class. Inferences from one risk class to another will require a separate cost of capital study for the particular risk class. However, within the same risk class differences in financial risk or leverage can be accounted for by moving up or down the pre-tax equity cost curve to the targeted equity ratio, by way of a leverage adjustment. This is not to say the Board needs to set different equity ratios for 82 LDCs. Our recommendation is to establish ROE guidelines for each sector, but give management some discretion based on their particular circumstances. Leverage adjustments are discussed in more detail in Appendix E.

In addition, using a simple interest-rate related formula (i.e. interest coverage) to determine the adequacy of ROE and for use in adjusting the allowed ROE going forward is likely to understate

ROE. As illustrated in Figure 3, the interest coverage curve falls well below the equity cost curve, except for the point where there is zero equity. Conversely, at 100 percent equity, the interest coverage curve alone would instruct that ROE should be zero.[25] However, even at 100 percent equity there is a return due to equity investors. Interest coverage ratios provide security for debt holders, but say very little about the adequacy of what is left over to meet the requirements of equity holders. As discussed previously, required equity returns are based on expected returns given the prescribed level of risk and what is available for competing investments of like risk.

Figure 3: Difference Between Bond Coverage and the Cost of Equity



The NEB's recent TQM decision makes several important points related to capital structure and its relationship to the cost of common equity. The NEB noted:

> The Board is of the view that while estimating the equity ratio based on business risk, separately from the determination of the return on equity, can be useful in a regulatory context, it does not reflect the way that much of the business world approaches capital structure and capital budgeting decisions.[26]

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25 The question used to draw an interest coverage curve is described in Appendix B.

26 Op. cit., at 17.

Further, in endorsing the ATWACC approach, the NEB wrote: "This offers the potential to avoid separating two elements that are inevitably linked: capital structure and the return on equity."[27] Concentric is of the view that the OEB must reflect differences in capital structure in its ROE determinations, and this can be effectively accomplished through our recommended approach in Appendix E.

Question 3: Should the approach to setting cost of capital parameter values differ depending on whether a distributor finances its business through capital markets or through government lending such as infrastructure in Ontario or through bank lending? If so, what would be the implications, if any, of doing so?

Response

No. Although the cost-of-capital parameter values may differ between utilities, the approach to setting cost of capital should be the same for all utilities consistent with the stand-alone principle. For example within a reasonable range, the ratemaking capital structure should match the capital structure that the utility has adopted based on its own circumstances. Similarly, the cost of equity component of the rates should be based on the cost of capital determined for proxy companies, and then adjusted for any differences in capital structure or risk between the specific utility and the proxy group. To the extent that government lending allows a utility to borrow at below-market interest rates (although this is not evident in Ontario), that lower cost should be passed through to ratepayers. At the same time, equity that exists in the capital structure should receive a rate of return that is equivalent to what that equity could earn in an alternative investment of comparable risk.

There are several reasons for setting the allowed rate of return on common equity for government-owned utilities equal to the cost of common equity of independent utilities. First, to establish fair competition between utilities, a consistent approach is required. Otherwise, a subsidized electric utility, for example, would have an unfair competitive advantage in the same service area over a private gas utility. Second, to send proper price signals to consumers, rates should reflect full costs for all costs of service. Otherwise, the Board would be incentivizing consumption, counter to Provincial energy efficiency objectives such as those included in the Green Energy and Green Economy Act of 2009 (the "GEGEA").

[27] Ibid, at 19.

The one exception would be if the income earned by municipal utilities used to fund dividends paid to their government owners are non-taxable. In that case, the pre-tax cost of common equity would be lower for a government-owned utility. However, it is our understanding that Ontario's utilities pay federal and provincial taxes (PILs) equivalent to privately-owned utilities, so this is not a factor.

In summary, other than flowing through actual debt costs and eliminating the tax allowance from rates (to the extent the government or municipal utility has a tax advantage), there is no economic reason to treat government-owned or government-financed utilities any differently than privately-owned utilities when it comes to setting an allowed rate of return on rate base. In addition, to the extent that there is a government policy to encourage consolidation and/or privatization of small utilities, treating all utilities of the same type (i.e., electric utilities v. gas utilities) the same will eliminate the disincentive posed by an artificial advantage in the apparent cost of capital enjoyed by government-owned or financed utilities where risks are borne by taxpayers and not reflected in rates.

V. CHOOSING A COMPARATOR GROUP

Question 4: Does the analysis in the Concentric Report provide a reasonable foundation for satisfying the comparable investment standard?

<u>Response</u>

Not entirely. In the referenced Report, Concentric was engaged to assist the OEB in evaluating the claims of natural gas utilities that the Return on Equity ("ROE") awards in Ontario were lower than those of other jurisdictions. The Board requested Concentric to provide a report that, among other things, compared awarded ROEs in other jurisdictions to those awarded in Ontario and analyzed the forces that contributed to any differences. The Concentric Report noted that allowed returns between the U.S. and Canada were in virtual parity in 1997, when the Ontario ROE Formula was established, and that there had been a growing disparity in allowed returns between the two countries ever since. The Report sought to identify any fundamental risk differences between Ontario's utilities and those in other jurisdictions that would justify the growing disparity in allowed returns. Concentric analyzed operating and financial data for the companies themselves, as well as territory and country-specific factors for the jurisdictions and countries in which they operated, specifically, addressing: (1) operating and financial characteristics; (2) differences in regulatory protection and rate stabilizing mechanisms; and (3) macro-economic factors including taxation policies.

On the whole, the Concentric analysis found that:

1. There were no evident fundamental differences in business and operating risks faced by Ontario utilities, compared to those faced by U.S. companies or other provinces' utilities that would explain the difference in ROEs;
2. That although regulated gas utilities in the U.K., the Netherlands, and Australia bear certain resemblances to Ontario's gas utilities, fundamental differences weaken the comparability of utilities in those markets, and accordingly those utilities should not be considered reasonable benchmarks for Ontario's utilities; and
3. Canadian utilities compete for capital essentially on the same basis as utilities in the U.S. In other words, taken as a whole, U.S. gas utilities were not found to be demonstrably riskier than Canadian gas utilities. Concentric's analysis identified interest rate trends combined with differing ROE methodologies as the principal factors underlying the disparity in returns.

Concentric's conclusions were seconded by the NEB TQM Decision which also found that U.S. utilities are useful proxies for investment opportunities and that they provide meaningful comparisons for Canadian utilities. The NEB decision affirmed that the U.S. and Canadian economies are interdependent, U.S. and Canadian companies are competing for investment capital, the North American energy markets are highly integrated, the U.S. and Canadian regulatory models are based on the same fundamental principles, and that the risks of regulated utilities in either of the two countries, though not identical, are sufficiently alike to render them meaningful comparators.[28] These findings suggest that it is reasonable and appropriate for the OEB to consider the investment returns provided by U.S. utilities when assessing whether the allowed ROE in Ontario satisfies the Fair Return Standard.

Although the Concentric report may have set a foundation for satisfying the comparable investment standard by establishing that U.S. and Canadian utilities were meaningful comparators, it did not in

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[28] NEB, RH-1-2008, Op. Cit., page 66-71.

itself, nor was it intended to, satisfy the comparable investment standard for purposes of evaluating the fairness of ROE determinations for Ontario's gas and electric utilities. The Comparable Investment Standard requires a comparison of the returns of like risk utilities. Although the Concentric Report provided sufficient basis to conclude that U.S. and Canadian utilities were indeed comparable enough to use as comparator or proxy companies, further analysis is required to select only those utilities determined to be of similar risk for comparison to Ontario's utilities.

Question 5: If not, what might the Board use as a comparator group?

Response

Satisfaction of the Comparable Investment Standard requires a detailed risk analysis in order to determine whether the average risks of the comparator group adequately represent the financial, regulatory and operating risks of the subject companies. The comparable group of utilities need not be identical in risk, but known differences that could impact the ROE determination should be factored into the analysis with an appropriate adjustment to the comparable group results. Generally, the first step in establishing comparability in cost of capital proceedings is selecting a proxy group from carefully specified screening criteria.

To select a proxy group for Ontario's gas and electric distribution utilities, the screening criteria should be sufficiently broad to include a representative group of companies, but narrow enough to hone in on dominant risk characteristics of the company, i.e. regulatory environment, business focus, credit rating, etc. This requires that companies used as comparators have businesses focused on regulated operations since only a specific set of risks are being evaluated, i.e. the risks associated with gas distribution, electric distribution or electric transmission. The more diversified the comparator the more inconclusive the risk analysis, as diversified businesses have offsetting risks within the holding company structure.

Screening criteria for electric and gas utilities would generally begin with the population of publicly traded, dividend-paying corporations within the same industry, with sufficient growth rate and market inputs to perform the various ROE analyses. At a minimum this would include, historical stock prices, historical dividends, forecast growth rates, and estimates of beta. These companies should share like credit ratings, and revenues should be primarily derived from the regulated operations of the sector. Concentric has performed a full proxy group selection for each of the sectors of Ontario's utilities. Please see Appendix C for the selection of the proxy group companies for Ontario's electric transmission and distribution, and natural gas distribution utilities.

In summary, Concentric initially studied the risk attributes of Ontario's gas utilities relative to U.S. gas utilities, concluding generally that U.S. utilities were not found to be demonstrably riskier than Canadian gas utilities. Since the issuance of the referenced June 2007, Concentric Report, Concentric has been engaged in a number of studies which have similarly examined the business and regulatory risks of both U.S. and Canadian electric and gas utilities. Concentric's conclusions in the referenced Concentric 2007 Report are supported by these subsequent studies completed for Hydro One and the Coalition of Large Distributors ("CLD"), testimony before the AUC in the Alberta Generic Cost of Capital Proceedings, and recent submissions to the OEB in this consultative process. Similarly, a detailed comparative risk analysis of publicly-traded North American gas and electric distribution utilities (selected according to proxy group selection criteria) and Ontario's utilities has been performed in Appendix D to this Report. From that analysis the following conclusions were reached:

- Ontario utilities have much greater financial risk than do the North American proxy group companies,
- We have not identified any business profile characteristics that would in themselves render our proxy groups incomparable to the Ontario utilities. Generally, the gas and electric utility proxy groups share similar business profiles to the Ontario utilities.
- Ontario's utilities face enormous capital requirements to develop the necessary infrastructure to satisfy Ontario's green energy initiatives over the next several years. We are aware of no single jurisdiction, outside of the Canadian provinces, that share the same upcoming capital burden.
- Lastly, we have examined the regulatory protection afforded the proxy group utilities and the Ontario utilities through their rates. We have conducted a comparative analysis of risk-mitigating regulatory mechanisms, employed to: stabilize sales volumes, recover fuel costs, reduce regulatory lag, support financial stability, address cost increases, expedite cost recovery of large capital projects, and provide a means for recovering unexpected variations in expenses, to assist in indentifying the risks to which a utility remains exposed. Though we found the Ontario utility group to have differences in its regulatory mechanisms from the North American proxy groups, the differences were offsetting. The proxy group companies reveal a broader range of protection; but, on average, both groups share comparable regulatory support in shedding risk. We have found no basis to conclude that an adjustment would be warranted to account for risk differences between the Ontario utilities and the

> proxy group other than for the additional debt leverage in Ontario. Their risks are, on average, the same.

Similarly, the NEB recent TQM decision is supportive of our analysis and conclusions that the regulatory models and risk characteristics between U.S. and Canadian utilities are comparable.[29] An excerpt from the TQM decision and the Board's findings on U.S. and Canadian utility comparability follows:

> In light of the Board's views expressed above on the integration of U.S. and Canadian financial markets, the problems with comparisons to either Canadian negotiated or litigated returns, and the Board's view that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008.[30]

Our analysis reveals, that though there are differences between the mechanisms employed to address the many risks a regulated utility faces, the level of risk mitigation via rate mechanisms between the Ontario utilities and proxy group utilities are comparable, though the mechanisms themselves may be different. As the NEB has indicated in the excerpt above, if differences in the level of risk between the two groups were identified, it would be appropriate to account for them in the cost of capital analysis with an adjustment. We, however, have found no measureable differences between the proxy group average and the Ontario utilities that would warrant such an adjustment. A full discussion of our risk analysis can be found in Appendix D and the supporting schedules can be found in Exhibit 4. In addition, a full cost of capital analysis can be found in Appendix F.

Question 6: Were the Board to only consider the use of Canadian utilities as a comparator group, is there an issue with circularity, given that the ROEs of these utilities are, and have been established by a mechanism similar to that currently used by the Board?

<u>Response</u>

Yes. The most significant difficulty in determining whether the comparable investment standard has been met for Ontario's utilities is finding comparable companies with comparable risks, whose returns are not subject to the Ontario Formula. With the exception of new NEB Group 1 pipelines,

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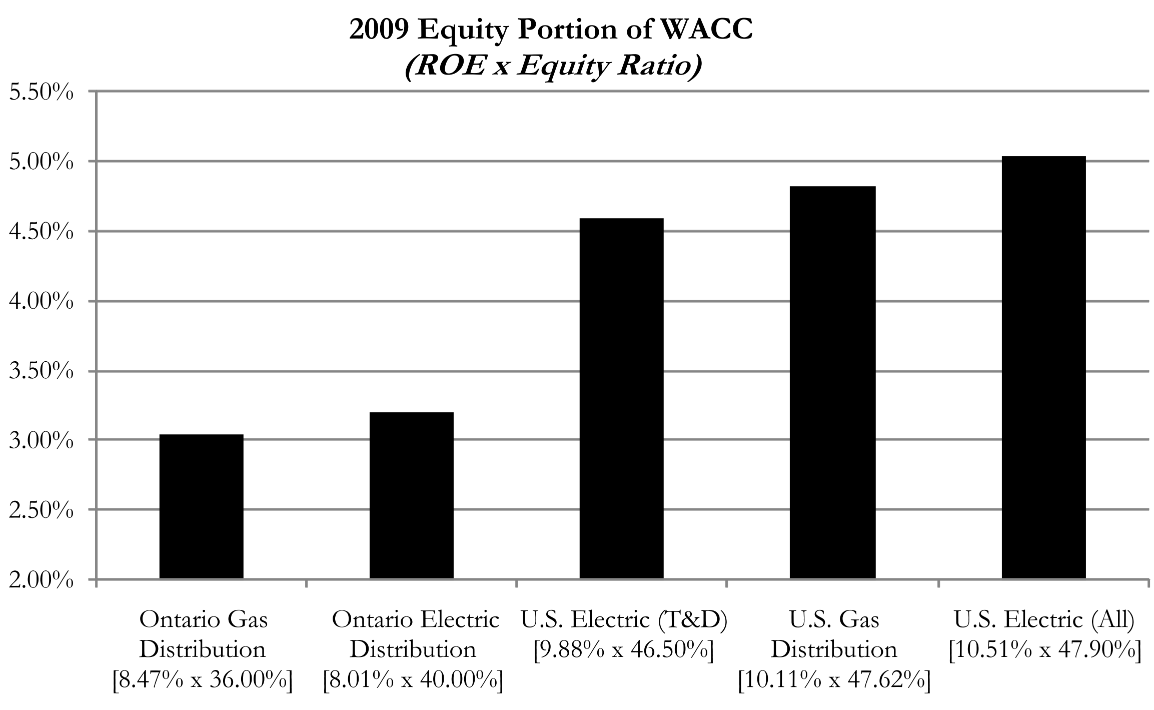
29 The North American proxy groups of publicly-traded natural gas and electric distribution utilities are comprised of U.S. companies.

30 NEB Reasons for Decision, RH-1-2008, TransQuebec and Maritimes Pipelines, Inc., Cost of Capital for 2007 and 2008, March 2009, p. 71.

Canadian utilities' authorized returns largely fail to provide meaningful information for comparison due to the circularity stemming from the widespread use of the formulaic ROE model across Canada. To evaluate the fairness of those ROE awards by looking to other Canadian utilities who are subject to the same formula is a meaningless exercise. Differences would stem only from timing of the calculation. The certainty of circularity of such a benchmarking analysis renders it useless as an independent source of comparability. In Ontario, except for utilities operating under specific settlement agreements or litigated returns, all utilities are assigned ROEs based on formulaic results and deemed equity ratios. Though a Canadian DCF or CAPM analysis would incorporate market derived inputs (i.e. stock prices and beta estimates) arguably, a degree of circularity remains, as stock prices and beta estimates still reflect investors' expectations of formulaic returns. To alleviate any concerns over circularity in deriving Ontario utility returns, North American utilities that are comparable in terms of risk and operating environment, and whose ROEs are determined by litigated Commission decisions through the application of a fair return standard emanating from the same basic regulatory principles, provide the best means by which to assess fairness in terms of the comparable investment standard.

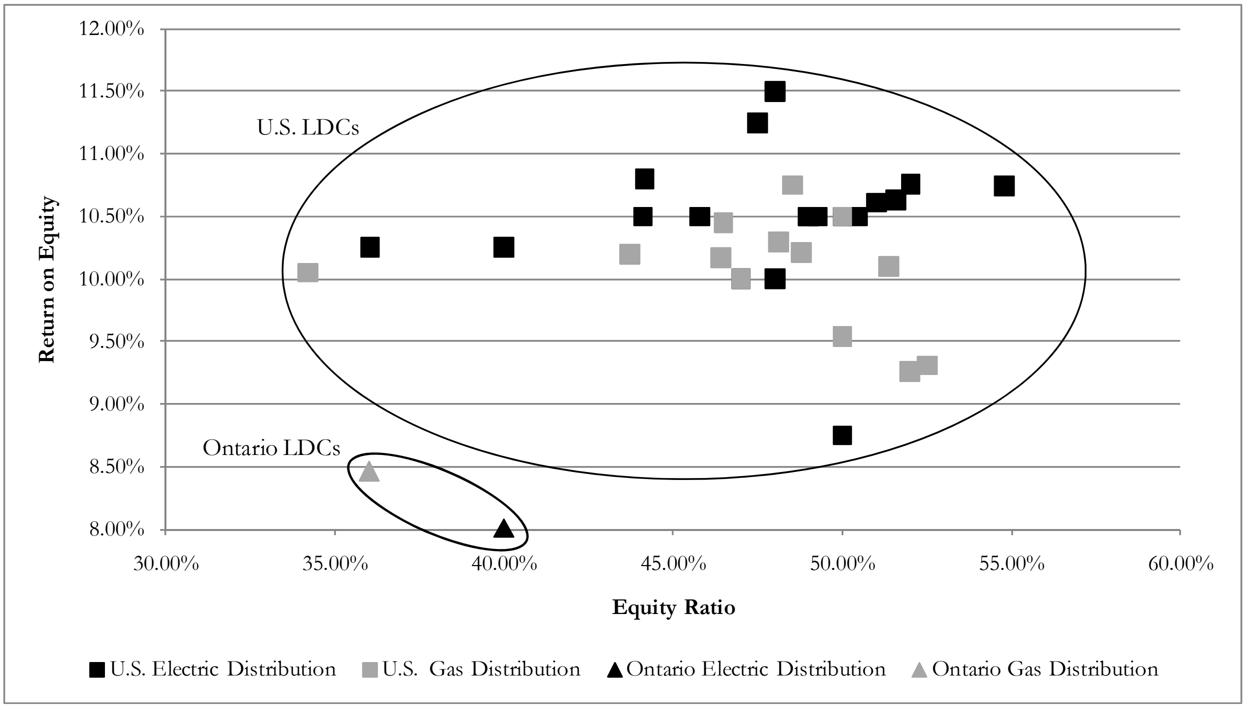
Figure 4: Ontario Authorized Returns vs. U.S. Utilities



A snapshot of current ROE awards across Ontario and the U.S. indicates that the ROE awards for Ontario electric utilities of 8.01 percent (assuming they were rebased to the Formula) and for Ontario's gas utilities of 8.47 percent for 2009 are substantially below those for comparable utilities in the U.S. Because ROE and equity ratio determine the portion of the WACC attributable to shareholders, allowed returns should be considered in the context of their equity ratios. The Figure above presents the products of the mean authorized returns and equity ratios of investment grade utilities in the following sectors: electric utility (including vertically integrated utilities), electric transmission and distribution (T&D) utilities, and natural gas distribution utilities. As the Figure indicates, the mean allowed ROE for all electric utilities in the U.S. in 2009 was 10.51 percent on 47.90 percent equity/capital; and for a subset of pure electric transmission and distribution companies was 9.88 percent on 46.50 percent equity/capital, 187 basis points above the Ontario Formula return. Similarly, natural gas distribution utilities in the U.S. received ROE awards averaging 10.11 percent on 47.62 percent equity/capital in 2009, 23 basis points above electric T&D, and 164 basis points above the average Ontario generic gas return of 8.47 percent. In Concentric's research on this topic, no macroeconomic factors, regulatory risks, operating risks, or financial conditions have been identified to justify the disparity in returns between Ontario utilities and their U.S. counterparts. As such, the end result achieved by the current Ontario Formula, in terms of overall return, measured against the *Hope* standard and Canadian principles of a fair return, is not comparable, and therefore does not satisfy the requirement of a fair return.

It is clear that limiting analysis only to other Canadian utilities, whose returns are also tied to the same Formula, would bias the results and falsely imply that the Formula is indeed meeting the requirements of the comparable investment standard, when it is virtually being compared to itself. Without viewing the results of the Formula in the context of equity returns determined by market forces or independent analysis (as opposed to a linear calculation tied to interest rates), a true comparison has not been effected. The primary question to consider is whether the Formula is producing results that equity investors would view as being comparable to those available for alternative investments of similar risk. The Figure below, which represents a scatter diagram of 2009 Ontario and U.S. allowed returns for individual operating companies in electric or natural gas distribution, suggests that the Formula is not producing such results. Again, as Figure 5 clearly shows, Ontario returns and equity ratios are much lower than litigated North American returns.

Figure 5: 2009 Authorized Returns and Equity Ratios (U.S. and Ontario)



VI. FORMULA-BASED APPROACHES AND THE EQUITY RISK PREMIUM

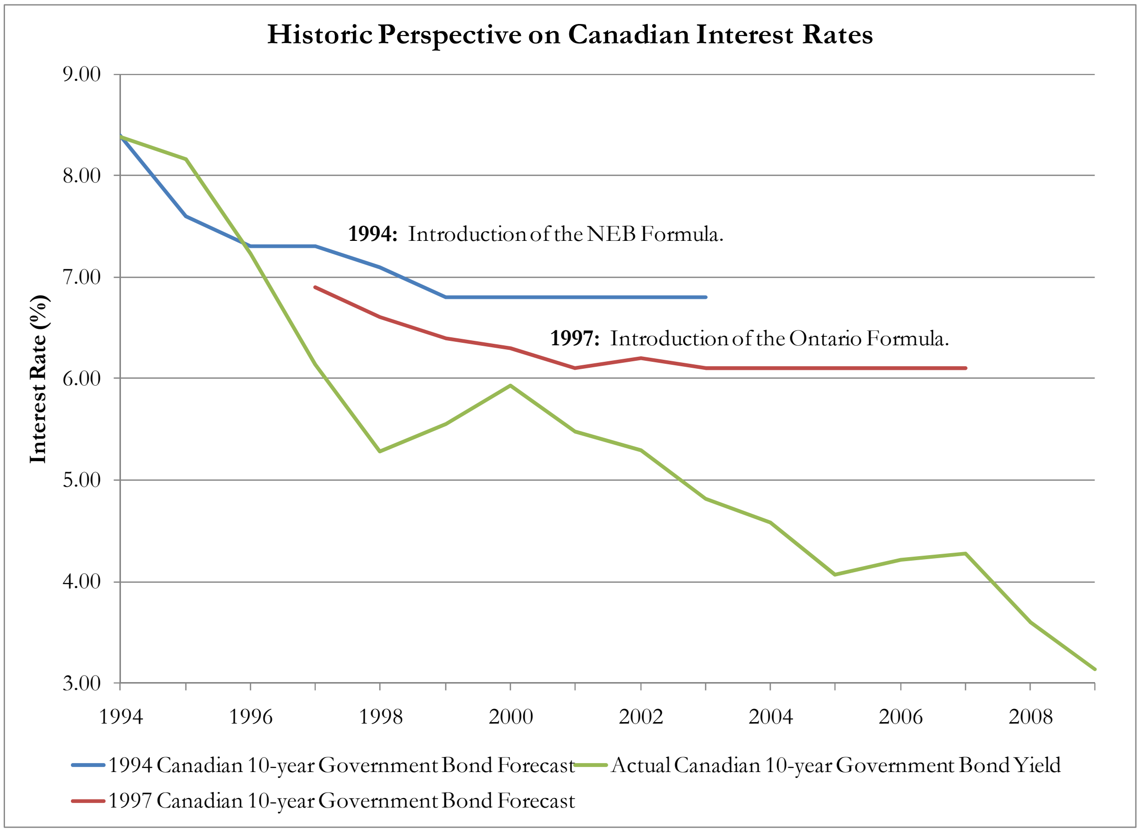
Question 7: Should the ERP approach be reset given that when the formula was first established the reference bond rate was 8.75%?

<u>Response</u>

Yes, assuming the Board decides to continue to use the ERP approach. As noted by the Board, the equity risk premium was established in 1997 when the Long Bond yield was approximately 8.75%. Since then, Long Bond yields have steadily declined. As a general premise, as bond yields decline, the required equity risk *premium* moves inversely or increases, but by a lesser amount. The Board attempted to account for this relationship with a formulaic factor of 0.75 to apply to the change in the Long Bond, thereby establishing some moderation in the relationship. Accordingly, although the formula return moves up and down with Long Bond yields, the effect is dampened because the equity risk premium implied by the Ontario Formula moves inversely to interest rates by a factor of 0.25 or (1 – 0.75).

If one were to examine the long bond forecast utilized when the Ontario Formula was originally adopted by the NEB, it is evident that bond yields were expected to remain relatively constant. During periods of economic contraction and financial distress, there is invariably a "flight to quality" as investors seek the safety of government bonds which are backed by the faith and credit of the federal government. As the price of those government bonds is bid up, the yield, or interest rate, declines. Therefore, when the allowed ROE is based primarily upon a formula that relies on the Canadian Long Bond yield, it creates the perverse effect of reducing the allowed ROE at the precise moment that investors are becoming more risk averse and demanding a higher return to attract capital. In Concentric's view, this is an unintended consequence of the generic ROE Formula. Concentric suspects that Canadian regulators never envisioned the steady decline in government interest rates, relative to returns on other investments, that has occurred since the first generic formula was adopted in Canada in 1994 or in Ontario in 1997. Below, for example, are two long-term bond yield forecasts, widely used by utilities in regulatory proceedings that prevailed at the time commensurate with the NEB's original cost of capital decision adopting the formula benchmarked to long-bonds in 1994 and Ontario's similar decision in 1997.

Figure 6: 10-Year Government Bond Forecasts in 1994 and 1997 versus Actual



Sources: A Digest of International Economic Forecasts (October 1994), Consensus Economics (April 1997), Bloomberg

The chart illustrates, at the time of the NEB decision, the expectation was that 10-year bond yields would fall from 8.8 percent in 1994 to 6.80 percent in 2004. In the case of Ontario, the expectation was that long-term government bond yields would fall from 6.9 percent in 1997 to 6.1 percent by 2007. Instead, government bond yields have fallen precipitously, and unexpectedly, to the 3.0 percent range embodied in the consensus forecast utilized in the current Formula. The low ROEs generated by the Ontario Formula today are the unexpected result of a seemingly reasonable methodology. The reciprocity, inherent in the Formula, reassured regulators that it would be fair. However, as government interest rates have done nothing but drop since its implementation in Ontario, it has become evident that the current Ontario Formula is not fair and is mis-specified by being tied too closely to government bond yields.

As demonstrated by Concentric's research on this topic and illustrated in the regression results shown below, the sensitivity of the equity risk premium to government bond yields is actually closer to 0.45. This has been one of the fundamental problems with the existing adjustment mechanism. The coefficient of 0.75, which was arrived at somewhat arbitrarily[31], appears to have mis-specified the historical relationship of government bond yields and authorized return. The cumulative effect of an unremitting downward trend in government bond yields in combination with a risk premium that is understated relative to changes in bond yields, has led to the growing disparity between U.S. authorized returns and Ontario authorized returns.

In our earlier comments to the OEB, we assessed the reasonableness of the elasticity factor of 0.75 in the Ontario Formula by performing a regression using U.S. utility authorized return data as the dependent variable to quantify this historical relationship. We selected U.S. LDC utility returns as they provide a robust data sample of North American litigated returns outside of the Canadian market dominated by the Formula. The regression results are replicated below:

Table 5: 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 + (B_1 * 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, and one could argue that additional information is required that would improve the R^2s, they do indicate, consistent with those we have estimated previously,[32] that the typical elasticity factor of U.S. authorized returns to government bond yields has historically been closer to 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

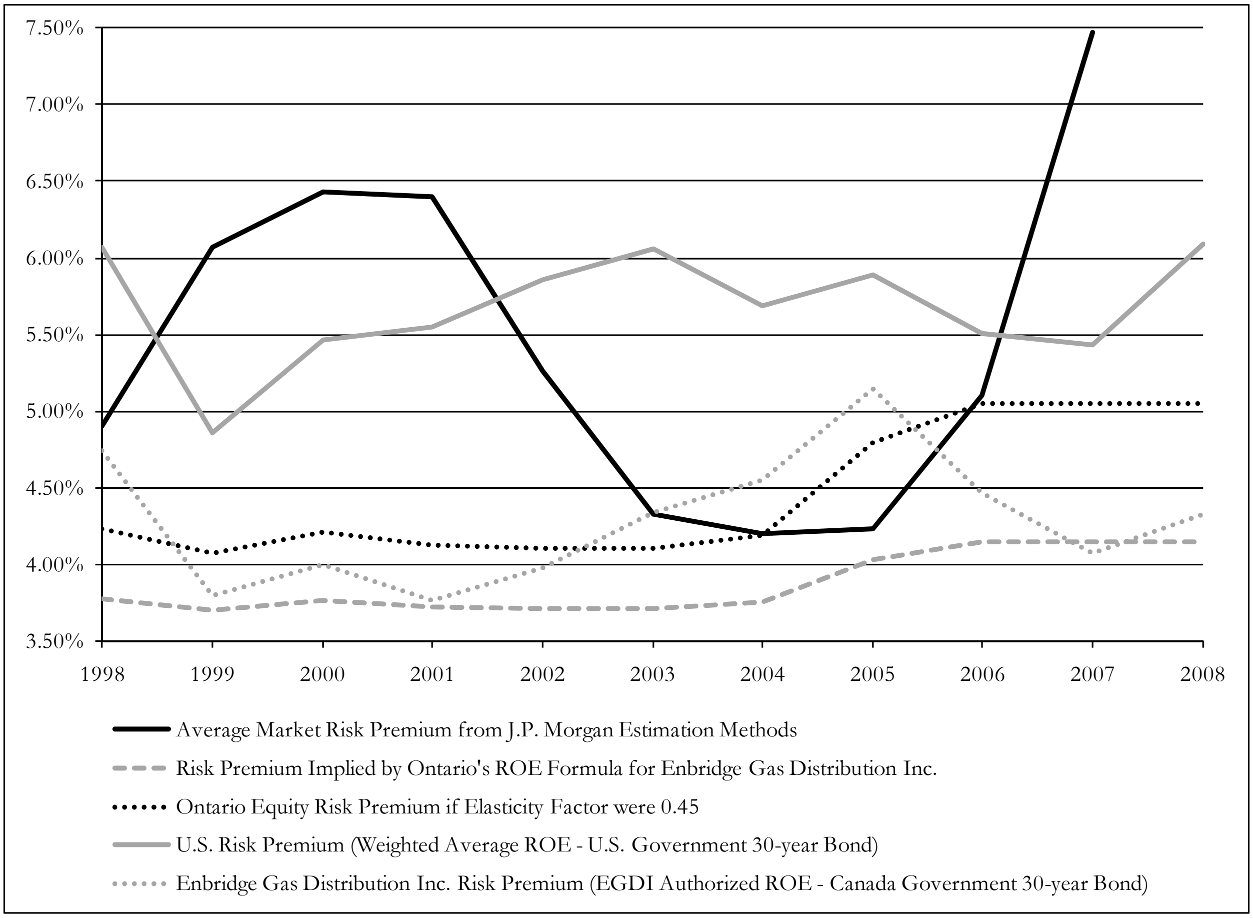
31 OEB, *Draft Guidelines on a Formula-Based Return On Common Equity for Regulated Utilities* (March 1997), at 31-32, where the Board stated: "Ratios contained in the evidence from generic rate of return proceedings in other Canadian jurisdictions ranged from 0.5:1 to 1:1. In addition some experts contend that the nature of the ratios will vary depending on the level of forecast bond yields. Based on a review of this rather unscientific evidence, the Board is persuaded that a non-linear relationship between interest rates and equity risk premiums does in fact exist and believes that an adjustment factor of 0.75:1 is fair and reasonable, though admittedly somewhat arbitrary."

32 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.

government bond yield (as opposed to the 0.25 implied by the Formula). This mis-specification 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 still not provide an ROE result that is either sufficiently responsive to existing economic conditions or "fair".

In our earlier comments in this process before the Board, Concentric 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 then compared those 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 reported the average of 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. Past relationships do not necessarily result in a return that is fair under variable market conditions. Accordingly, benchmarking the Formula-produced-return with alternative measures of cost of equity, with adjustments as appropriate, are essential to ensuring a return that is "fair".

Figure 7: 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".

As indicated above, the equity risk premium (as measured through U.S. litigated returns) is much more responsive to interest rates than the Formula coefficient would indicate. Further, risk premiums do not always behave according to their past relationships and even a properly specified formula based on the past may not appropriately track current cost of equity capital. These factors suggest that an ERP approach tied to the Long Bond should be reset at more frequent intervals due to the volatility of the Long Bond yield and the inability of the Formula to adequately track capital costs in changing market circumstances. Even if accurate at the outset (i.e., the ERP was calculated from a reliable ROE estimate in relationship to the Long Bond), the Formula has proven that it can quickly get off track.

Question 8: Should the ERP approach be reset on a regular basis (e.g., every 4 or 5 years) to mitigate the issues described in the 1997 Compendium?

Response

In its 1997 Compendium, the Board noted the potential for the automatic adjustment mechanism to potentially lead to inappropriate results due to the time-sensitive and volatile nature of ERP calculations. The Board also noted that the parameters and adjustment factors would have a cumulative or compounding effect on the results of the formulaic ROE mechanism. As such, it is appropriate to set guidelines for allowing review of the Formula. Concentric is of the opinion that it is appropriate for the utilities or other parties to apply to the Board at any time if they are not satisfied with the results of the generic ROE process. The merits of such application should be evaluated by the Board to determine if a formal review of the Formula is required. Concentric also recommends the establishment of a periodic review period, i.e., every three to five years for the Board to review the performance of the Formula and perhaps to address concerns that were raised but not deemed to be of immediate import during the interim period.

The periodic reviews need not necessarily lead to full generic cost of capital proceeding or a resetting of the ROE, or a generic proceeding per se, but should provide a forum for the Board to hear evidence concerning the adequacy of returns as well as future processes or mechanisms that might be utilized to improve the determination of ROE and capital structure issues in future years. In Concentric's view it is important to provide flexibility to address problems with the Formula as they arise and as the Board deems necessary. However, predetermined check in periods should be maintained (every 3 – 5 years) to allow all parties the option (but not the requirement) to reset the Formula as well as providing a routine check on the performance of the Formula over the period and a forum for suggesting improvements or enhancements to the Formula.

Question 9: How might the Board address the potential issues arising from the application of the current methodology as a single point-in-time calculation?

Response

ROEs determined through the appropriate methods are forward looking at the time they are made. The Fair Return Standard applies regardless of whether or not market conditions are "normal." Markets change continually and the Board should base its decisions on the market conditions that exist at the time of the evidence to be considered in any given proceeding. The fact that market conditions are likely to change in the future is virtually a given. However, the very nature of markets ensures that the direction and magnitude of such future changes cannot be known with any certainty. For example, the Efficient Markets hypothesis suggests that if it is *known* that a stock price will increase in the near future, investors would immediately bid up the price to a level where there are approximately as many buyers who believe the price will go up, as there are sellers who believe the price will go down. The same is true for bond prices, yields and other observable conditions in the market.

The Efficient Markets hypothesis suggests that the "normal" condition is for market conditions to be an unbiased indicator of future expectations. There is no known way for a person to determine whether the current judgments in the market will ultimately be right or wrong. Hence, there is no known way that the Board could determine that markets are not "normal" at the time it makes a decision. Instead, the best the Board could do, and should attempt to do, is to make its decisions based on the market conditions that exist at the time the Board establishes the rate of return.

Question 10: How should the Board establish the initial ROE for the purposes of resetting the methodology?

Response

To ensure that the utility is provided with a fair return that enables it to meet its obligations and maintain its ability to attract capital, the Board must set a rate of return that compensates investors for the aggregate business and financial risks that they would expect to experience from a similarly structured firm with a comparable risk profile. Utilities typically fund their investments with a mix of debt, common equity and to a lesser extent preferred stock. The cost of debt can be directly determined by the interest rate charged by the lender and the cost of preferred stock can be determined by its dividend rate, but the ROE cannot be directly observed and must be estimated or inferred from other indicators. Estimation methods commonly employed by financial analysts in regulatory proceedings include the ERP Method, the Discounted Cash Flow ("DCF") Method, the Capital Asset Pricing Model ("CAPM"), Comparable Earnings of like-risk companies, and Comparable Authorized Returns.[33] As there is no single, widely-adopted and precise method for determining the ROE, more than one of these methods should be utilized in order to bracket the appropriate ROE for a given utility.

The bellwether *Hope* decision established a standard for the return on equity that remains the guiding principle for regulatory proceedings in both the U.S. and Canada:

> … [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[34]

Hope offers guidance on the methodology for setting ROE, whereby the Court distinguished between the methods employed and end results in terms of overall return for determination of a fair rate of return:

> Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling.[35]

Hence, the methodologies employed to set the return are not the controlling factor, but only whether the result is "just and reasonable". We are called upon to review our results in the context of other benchmarks to establish their reasonableness. We have already observed that one methodology – the ERP formula – can run afoul of the fair return standard in the absence of corroborating or reasonable checks from other inputs.

In its 1997 Draft Guidelines Compendium, the Board noted a number of considerations in applying the formula-based approach. First, the Board noted the importance of establishing the initial parameters, which it stated "will have a profound influence on the potential success or failure of the process."[36] Secondly, the Board noted that the "formula ROE generally relies predominately on the

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33 These methods are described in greater detail in Thompson, *Regulatory Finance: Financial Foundations of Rate of Return Regulation*, Kluwer Academic Publishers, pp. 27- 55; Morin, *New Regulatory Finance: Public Utilities Reports*, pp. 145-319; and Harrington and Wilson, *Corporate Financial Analysis*, Third Edition, BPI/Irwin, pp. 120-130.

34 Op. cit.

35 Ibid.

36 Draft Guidelines at 7.

equity risk premium method to the exclusion of these other methods and, hence, sacrifices the unique contributions of these other approaches."[37] However, although the Board recognized the merit of alternative approaches, it stipulated that the ERP approach should be used to evaluate the appropriate ROE for the Ontario utilities, due to its overriding concerns with the application of the DCF, Comparable Earnings and CAPM methodologies for Ontario's utilities. Those primary concerns were based on the lack of direct market inputs for Ontario utilities and the lack of an appropriate group of comparators. Specifically, the Board stated:

> The Board anticipates that, in assessing the initial implied risk premium and appropriate ROE for Consumers Gas, interested parties may consider all relevant issues with respect to the application of the equity risk premium test. This may include matters such as the nature of the relationship between interest rates and the implied risk premium, the need to adjust "bare bones" ROE for financing flexibility and the riskiness of Consumers Gas' equity relative to long Canada bonds and to the overall stock market. In addition, parties may wish to consider the results of the DCF test and the Comparable Earnings test as a means of checking the validity of the equity risk premium results.[38]

Consistent with its stated approach in the Compendium to the Draft Guidelines, the Board established the initial risk premium for the Formula, in its decision for Consumers Gas in EBRO 495, by considering an array of risk premium estimates put forward by experts and selecting a risk premium within the range of results presented. The risk premiums put forth by experts were either the result of directly measuring the historical relationship between bond yields and equity returns; or alternatively by deriving an implied risk premium, by backing-out forward looking bond yields from ROE estimates produced by using other methodologies, i.e. DCF, CAPM or Comparable Earnings.

Multiple approaches for determining ROE provide greater assurance that the end result will be just and reasonable, as conditions that may bias results could be detected or mitigated by considering alternative results. In Concentric's testimony before the AUC for ATCO utilities, primary reliance was placed on the CAPM and DCF results, with corroboration provided by reviewing a risk premium approach, comparable earnings of low risk industrials and allowed returns in other jurisdictions. Generally, for Ontario's utilities, the primary concerns noted by the OEB in its Draft Guidelines concerning alternative approaches, specifically the DCF and CAPM approach, remain: "common shares of the OEB-regulated utilities are no longer traded on the open market and, hence,

37 Ibid.
38 Ibid at 30.

only non-regulated company data is available to perform the test. This precludes the acquisition of the market data required to undertake a utility –specific discounted cash flow analysis."[39] And for the CAPM approach, "The fact that the OEB-regulated utilities are not traded on the market precludes the calculation of the beta value required to undertake the CAPM cost of equity analysis directly for these companies."[40] However, the Board's concerns can be addressed by using carefully specified comparable groups from other jurisdictions. It is not necessary that Ontario utilities have direct market inputs, when like companies of comparable risk exist that do have such inputs. Once a proper comparable group or series of groups is formed, fundamental ROE analyses can be performed using any combination of approaches to reset or recalibrate an appropriate and fair return. It should be noted that initial ROE results should be adjusted for differences in risk between the proxy group and the target utilities. Such risk differences might include significant differences in financial leverage, which can be adjusted either by using the Hamada equation to unlever and relever beta in the CAPM model to account for such differences, or could be adjusted through the ATWACC equation, solving for ROE.

In Appendix F to this Report, Concentric has provided a complete cost of capital study for the Ontario utilities, using the DCF and CAPM as our primary analyses and the ERP and Comparable Returns as a means of benchmarking the reasonableness of the results of our primary analyses. A summary of those results by sector, adjusted for differences in leverage between the proxy group and the Ontario utilities, is provided below:

Table 6: Leverage Adjusted ROEs and Capital Structures for Ontario Utilities

SUMMARY OF RECOMMENDED COMMON EQUITY RATIOS AND APPLICABLE ROES							
	COMMON EQUITY PERCENTAGE IN BOOK CAPITAL STRUCTURE						
	34%	**36%**	**38%**	**40%**	**42%**	**44%**	**46%**
Gas Distribution	11.3%	11.0%	10.7%	10.5%	10.2%	10.0%	9.8%
Electric Trans. and Dist.	11.2%	10.9%	10.6%	10.3%	10.1%	9.9%	9.7%

39 Ibid at 5.
40 Ibid at 6.

As is matter-of-factly stated in Bonbright's Principles of Public Utility Rates, *The Fair Rate of Return*, "despite the apparent rigor and precision of the financial models used to estimate the cost of equity, much judgment is required in the application of these models. Elaborate modeling gives a false sense of precision", where in fact "no single group or technique is conclusive". *Hope* dictates that it is the end result that is important and not the methods used to arrive at the ends. Accordingly, the test of reasonableness and fairness to ratepayers and investors should be evaluated based upon the results it produces. "Determining cost of capital is not an exact science. It is based on as objective and comparable data as possible, but experience and judgment must be used in drawing conclusions".[41] Employing multiple methodologies to inform the analyst's recommendation, and to serve as a basis for evaluating the fairness of the results produced, is the appropriate course for setting the initial ROE.

VII. CHOOSING AN APPROPRIATE BASE FOR THE EQUITY RISK PREMIUM

Question 11: Is the government (of Canada) bond yield the appropriate base upon which to begin the return on equity calculation?

<u>Response</u>

The answer to this question is provided in two parts: 1) examining the role of the government (of Canada) bond yield in setting the base ROE under the DCF, CAPM or ERP methodology; and 2) managing the change to the base ROE in future years.

i. Role of Government Bond Yields in Setting the Base ROE

As we detailed in our Report for the OEB in 2007, the primary approaches to estimating ROE are inter-related. One factor, such as bond yields should similarly impact all methodologies. However, factors driven by economic cycles influence interest rates and equity valuations differently, thereby leading to differing results. Excerpts from that Report are repeated below:

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

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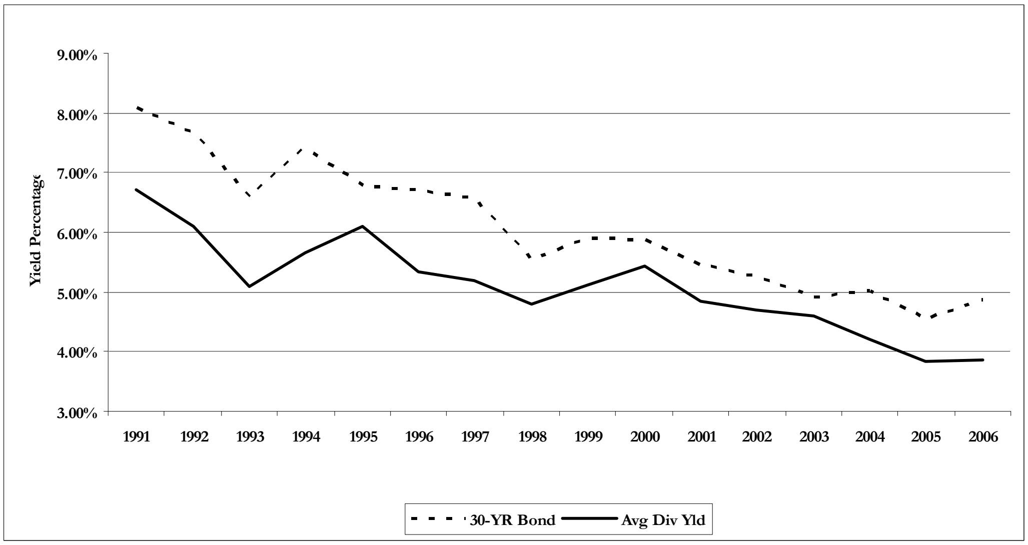
41 Quoted sections are from Bonbright, Danielsen and Kamerschen, Principles of Public Utility Rates, Second Edition, *The Fair Rate of Return*, at 317.

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.

Figure 8: Comparison of U.S. Gas Utility Dividend Yields and U.S. 30-Year Bond Yields for the Period 1991 – 2006[42]



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.

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

42 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.

industry specific factors that are reflected in stock prices, but are not accounted for by the level of interest rates.

Government bond yields are heavily influenced by changes in fiscal and monetary policy, as central banks use short-term interest rates to respond to economic conditions, which tend to decrease government interest rates while corporate capital costs may be increasing. The influences of fiscal and monetary policy on interest rates are likely to be profoundly different from the impact on corporate capital costs. This would lead to ERP and CAPM results based on government bond yields that differ substantially from results based on equity valuations, i.e. the DCF approach. For this reason, it is important to use multiple methodologies and weight the results of those methodologies based upon available market information. In today's economic environment an ROE estimate derived entirely on the historical relationship of government bond yields and equity returns will not provide adequate results due to abnormally low interest rates and abnormally high credit spreads. In summary to answer the first part of this question, government bond yields in themselves are not an appropriate base for setting ROE, multiple methodologies must be employed and afforded appropriate weight to arrive at an ROE that meets the fair return standard and is indicative of utility equity costs.

ii. Role of Government Bond Yields in Managing the Change to the Base ROE

In the recent market environment, corporate capital costs rose as a result of investors' response to the weakening of the economy and their increased aversion to risk. During periods of monetary easing and economic uncertainty, investors typically move out of more risky asset classes such as common equities and corporate bonds into safer asset classes such as government bonds and money market funds. This phenomenon, known as the "flight to quality" or the "flight to safety," drives down the yield on government bonds. Corporate bond yields, however, would be expected to increase during this same period because economic weakness increases the probability that some issuers will fail to meet their repayment obligations. This heightened default risk causes bond purchasers to require a higher risk premium on corporate bonds. It stands to reason if corporate bond purchasers require a higher risk premium on corporate bonds, and bond holders' claims are superior to those of equity holders, the risk premium required by equity holders would correspondingly increase.

The "flight to safety" phenomenon works in the opposite direction as well. When investors are more confident about economic growth and corporate earnings, they are willing to move money out of safer asset classes such as government bonds and money market funds and into more risky asset classes such as common equities and corporate bonds. Under this scenario, yields on government bonds would increase, but yields on corporate bonds would be expected to decrease as bond investors would become less concerned with the default risk of issuers. Thus, credit spreads between government and corporate bonds are not static and may diverge depending on the economic cycle. As a result, long term government bonds are not always good predictors of corporate capital costs.
Even if the Ontario ROE Formula failed to capture the magnitude of the change in the cost of equity capital, it should, at minimum, be directionally accurate. However, the recent economic recession and credit crisis illuminated the flaws in the Ontario ROE Formula. Namely, almost every market participant agrees that the cost of equity capital has risen in 2008 and 2009. However, the ROE Formula in Ontario generates a reduced allowed return because yields on the Government of Canada Long-Bond have fallen due to the "flight to safety" described above. The Formula has failed to accurately reflect the dramatic increase in investors' risk aversion and the associated upward movement in the equity risk premium. Had the ROE Formula been tied to corporate bond yields, the allowed ROE in Ontario would have risen slightly to reflect the higher risk premium. This higher ROE would be appropriate because it would properly reflect increased investor uncertainty as evidenced in the equity market by lower price/earnings ratios, higher dividend yields, and increased market volatility, and in the credit market by increased credit spreads to compensate for additional credit risk, default risk and liquidity risk.

This period of economic uncertainty should be viewed as an opportunity to "stress test" the ROE Formula because the Fair Return Standard requires that a utility be able to attract capital and maintain its financial integrity and flexibility under a variety of market conditions. Some will predictably argue that this period of uncertainty and volatility in the capital markets has ended, and that markets have now stabilized. However, the relevant point is that the ROE Formula is flawed and has failed to accurately track the cost of equity since before the economic crisis of the past two years. The OEB is not alone in relying on a financial model that failed to predict return requirements; however the failure of the Formula became acutely obvious when the financial market came under extreme stress and investors' risk aversion increased. Many investment banks and financial market participants are using this new information to recalibrate their own financial models in an effort to more accurately and precisely reflect investor behavior and market conditions. Likewise, the OEB should utilize this opportunity to make appropriate changes to its ROE method so that it will more accurately reflect the cost of common equity for regulated utilities in Ontario. Among those changes the Board should consider, is including a measure of corporate capital costs in the Formula.

The NEB provided the following justification for moving away from a formula that no longer appears to adequately track utility cost of capital.

> 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.[43]

Question 12: What is the relationship between corporate bond yields and the corporate cost of equity? Is this relationship sustainable?

<u>Response</u>

Historically, corporate bond yields and corporate costs of equity have enjoyed a strong correlation that reflects the market's perspective on corporate credit risk, an important component that has been missing from the existing Formula. Assuming the Board wishes to continue its reliance on a formulaic approach, Concentric believes that the corporate bond yield would be better suited for the ROE calculation under a variety of different market conditions, and would bring the market's perspective on risk into the equation.

i. Historical relationship between corporate bonds and allowed returns

Corporate bonds enjoy a strong relationship with regulated utility allowed returns. Linear regression of allowed returns of utilities included in the RRA database and the associated corporate bond yield average (for the 6 months prior to the ROE decision date, which could go back as far as 1989 to present), indicate that there is a statistically significant relationship between ROE and corporate

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43 Op. cit., at 17.

bond yields. The results of those analyses, provided below, indicate that the corporate bond yield has a slightly higher level of statistical significance as it relates to utility authorized returns compared with the long term Treasury bond (see Table 5).

Table 7: Regression Results Authorized Returns as a Function of Corporate Bond Yields

	Intercept	t-stat$_\alpha$	β_1	t-stat$_1$	R^2
Authorized Return Regression Model = Intercept + (B_1 * bond yield) = Authorized Return					
Moody's Corporate A-Rated Bond Yields (641 data points)	7.717	39.334	0.454	16.024	0.286
Moody's Utility A-Rated Bond Yields (641 data points)	7.627	39.976	0.464	16.960	0.310

Beyond the slightly stronger statistical relationship between corporate bonds and authorized returns compared to government bonds, the corporate bond is more suitable as a basis for the formulaic ROE determination, due to its lower volatility compared to government bonds, which provides a more stable basis for purposes of computing authorized returns. Since January 1997, in Canada, the average yield on the Moody's A rated utility bond has been 6.44 percent and standard deviation has been 0.66, which is 10.31 percent of the average. By contrast, the average yield on the 30-year government bond has been 5.15 percent, but the standard deviation has been 0.85, which is 16.35 percent of the average. In the U.S., the average yield on the Moody's A-rated utility bond has been 6.86 percent, and the standard deviation has been 0.83, which is 12.06 percent of the average. By contrast, the average yield on the benchmark 10-year Treasury bond has been 4.80 percent, but the standard deviation has been 0.92, which is 19.22 percent of the average. In other words, Treasury bonds have been more volatile than corporate bonds since January 1997. This volatility can be attributed to the fact that Treasury bond yields tend to be more sensitive to changes in the business cycle and short-term changes in monetary policy and investor sentiment, while corporate bond yields reflect the long-term ability of corporations to meet their interest and debt repayment obligations. This is reflected in the difference in the coefficients in the Table above.[44]

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44 One might correctly observe that the R^2's on these equations are relatively low, suggesting that other information is required to adequately predict the relationship between allowed ROEs and bonds. We address this issue with our index formulation that includes ROEs from North American litigated proceedings.

The Moody's A-rated utility bond has been utilized by the state of California in a formulaic ROE determination and has withstood the stresses of the recent economic crisis reflected by its continuing ability to provide fair returns despite the changed economic conditions. The major points of the California formula are as follows:

- The initial authorized ROE is based on the DCF and CAPM approaches;
- The adjustment is based on 0.50 of the annual changes in Moody's utility bond yields, not government bond yields;
- There is a 100 basis point deadband, meaning that if interest rates change by less than 100 basis points, either up or down, the ROE remains unchanged;
- A full ROE hearing is conducted every three years; and
- The decision emphasizes the importance of informed judgment by the regulator in setting the appropriate ROE.

In a recent decision, the California Administrative Law Judge discussed the relative merits of using a government bond yield or a corporate bond yield as the platform for the ROE formula:

> The purpose of an interest rate benchmark is to gauge changes in interest rates that also indicate changes in the equity costs of utilities. U.S. Treasuries are more sensitive to economic changes and risks in the international capital markets than utility bonds because they are bought and sold globally. However, U.S. utility bonds are generally affected less than Treasuries as a result of major shifts of international capital because a majority of U.S. utility bonds are traded with the U.S.
>
> Consistent with our use of utility bond interest rates in ROE, PBR, and MICAM proceedings and desire to use an index that more likely correlates and moves with utility industry risk, utility bonds should be adopted for the CCM (Cost of Capital Mechanism) index. In this regard, the Moody's Aa utility bond rates should be used for those utilities having an A credit rating and Moody's Baa utility bond interest rates for utilities having a B credit rating.[45] (Emphasis added.)

As the California ALJ's decision correctly observes, utility bond interest rates are more likely to correlate and move with the utility industry risk. Since the purpose of the generic ROE formula is to gauge changes in interest rates that correspond to changes in the cost of equity for utilities, the interest rate on corporate utility bonds is the correct benchmark.

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45 *Application of Southern California Edison Company (U338E) for Authorized Cost of Capital for Utility Operations for 2008 and Related Matters*, Decision of ALJ Michael J. Galvin, mailed April 29, 2008, at 13.

ii. Historical relationship between government bonds and corporate bonds

The Table below shows that although corporate bond yields are highly correlated and enjoy a strong historical relationship to government bond yields, they do differ. In Concentric's opinion, those differences are attributable to factors such as economic business cycle and influences of federal monetary policy, that do not enhance the fairness of a government bond derived ROE, but rather detract from it.

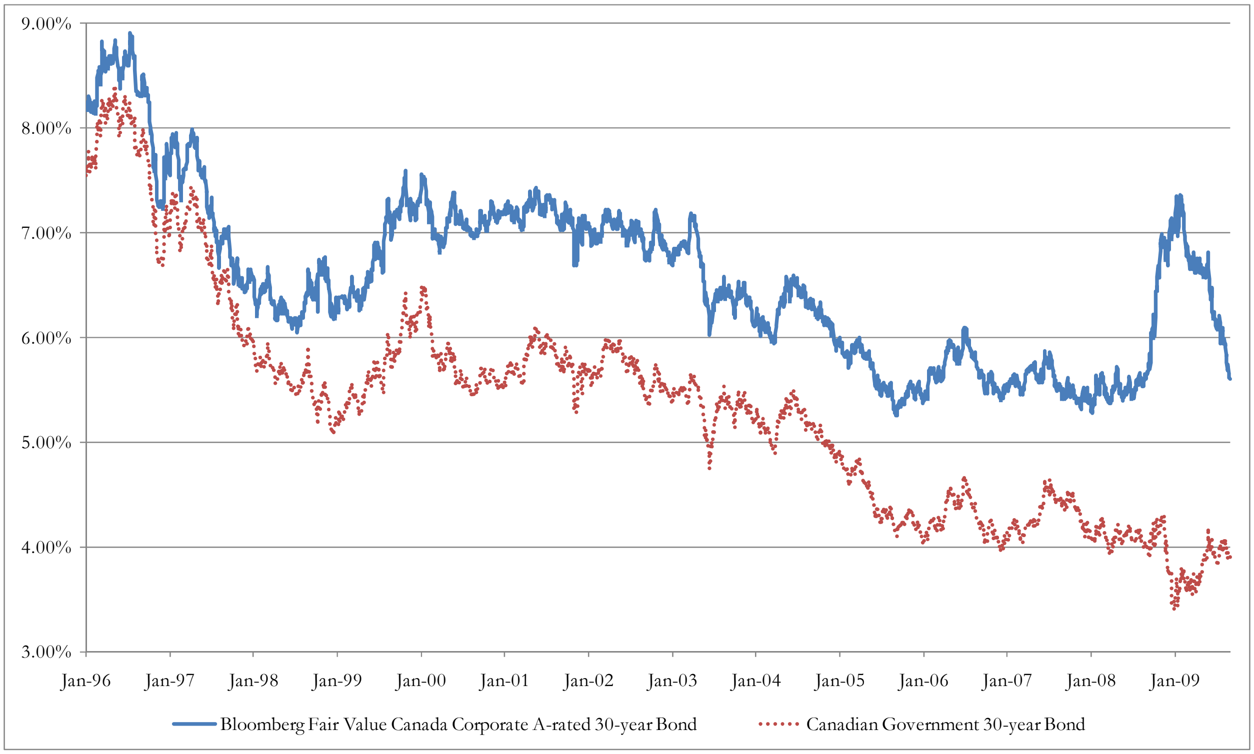
Table 8: Regression Results – Moody's 30-Year Corporate A Rated Bond Yields as a Function of U.S. 30-Year Treasury Bond Yields

	Intercept	t-stat$_{\alpha}$	β	t-stat$_{x}$	R^2
Moody's Corporate A-Rated Yield = Intercept + (β * Treasury Yield)					
Daily Yields December 24, 1992 – present (4,150 data points)	3.117	71.593	0.70	91.693	0. 669

As the regression results above suggest, statistically, there is a 311.7 basis point historical spread between U.S. 30-Year Treasury bond yields and the Moody's Corporate A bond yield, which increases or decreases by a factor of 0.70, with the change in long term government bond yields.

The graph below shows the divergence between corporate bonds and government bonds that occurred from September 2008 through early 2009. Likewise, the credit spreads increased dramatically as the corporate bond moved higher and the government bond moved lower. For example, in December 2008, the average spread between A-rated utility bonds and 30-year Treasury bonds was 368 basis points compared to the historical average of 166 basis points since March 1997, when the ROE Formula was first adopted in Ontario. A proper determination for regulated utilities in Ontario requires a formula that is more responsive to the higher risk premiums required by investors for the increase in credit spreads than that currently provided by the Formula.

Figure 9: Government and Corporate Interest Rates January 1996 – August 2009



Although much of the data gathered for the above analysis has been performed using U.S. allowed returns, and U.S. bond yields, the figures below reflect that the U.S. and Canadian debt markets move in tandem. Based on the positive relationship between U.S. and Canadian debt markets illustrated below, we would not expect the results for a purely Canadian analysis to be materially different.

In summary, Concentric finds that the Corporate bond yield provides a more suitable basis for the ROE Formula than the government bond yield. Our analysis has indicated that the sensitivity of the corporate bond to allowed returns is roughly from 0.45 – 0.50.

Figure 10: U.S. and Canada Long Term Federal Bond Yields 1996 - 2009

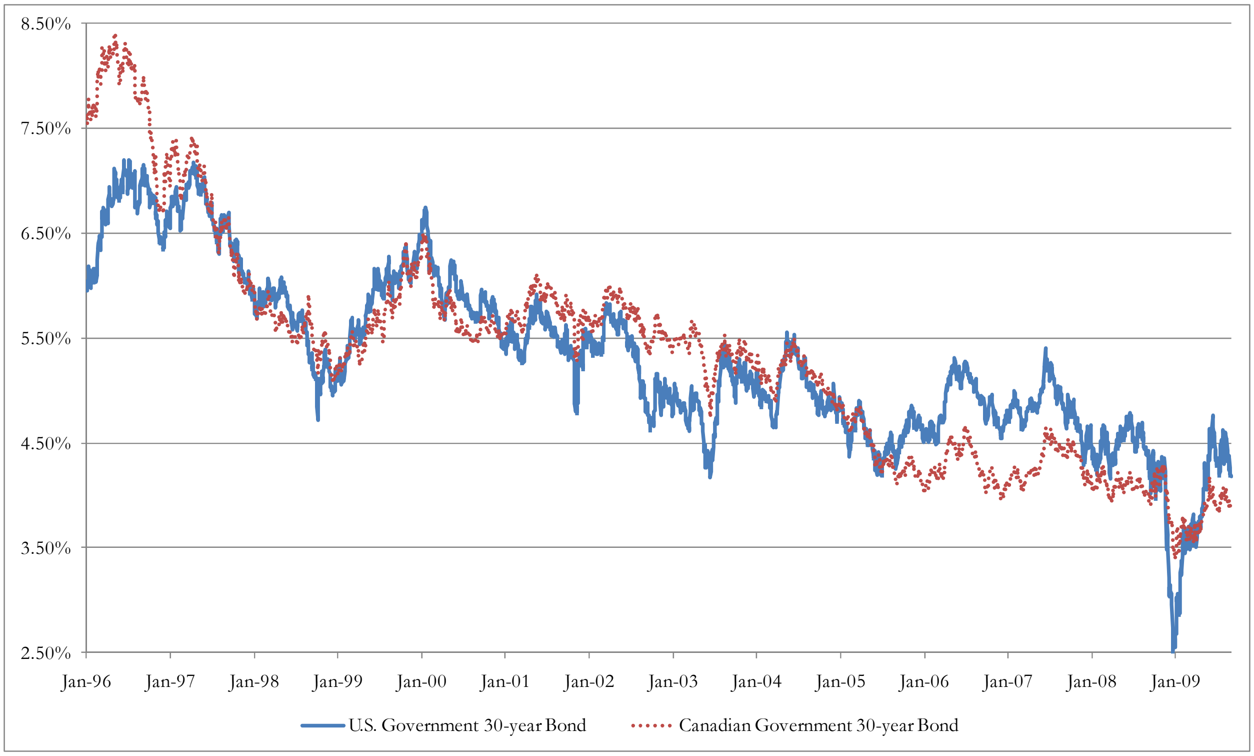
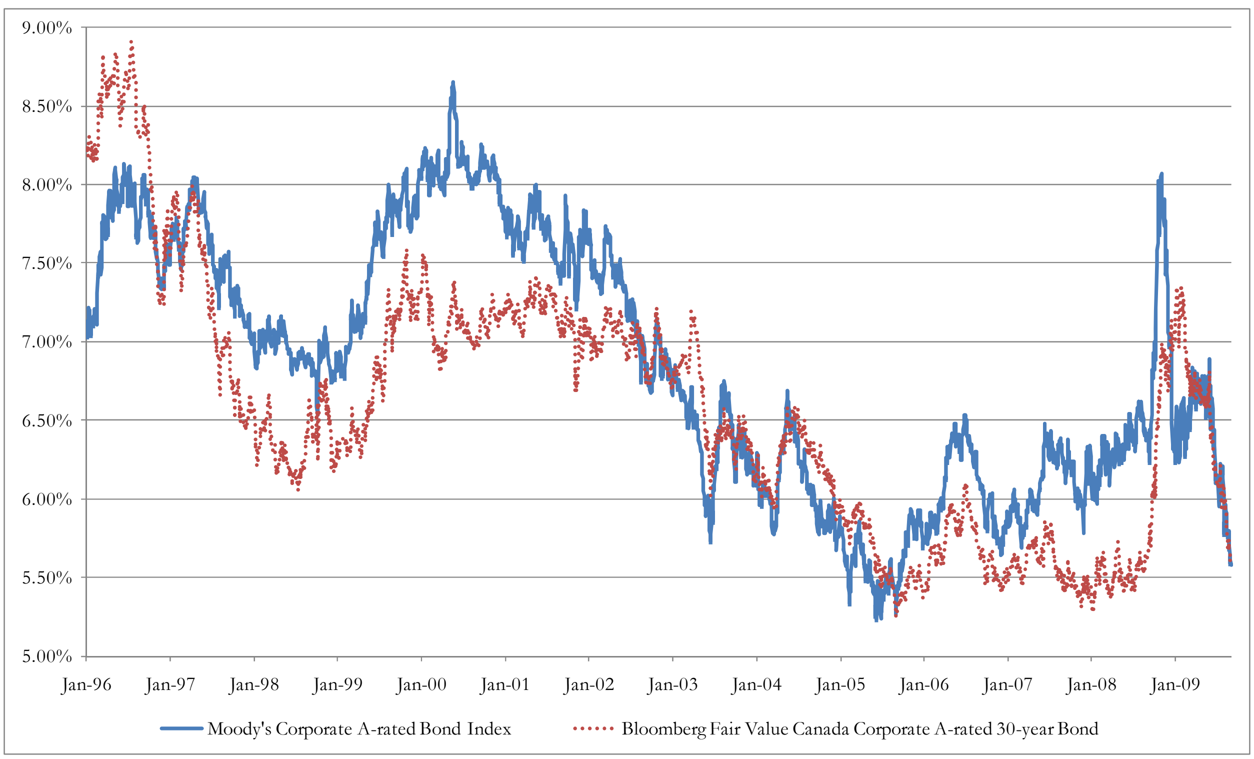


Figure 11: Moody's Corporate A vs. BFV Canada Corporate A Bond Yields 1996-2009



VIII. CALCULATING THE EQUITY RISK PREMIUM

Question 13: Does the current approach used by the Board to calculate the ERP remain appropriate? If not, how should the ERP be calculated?

Response

No, the Board's current approach to calculating the equity risk premium ("ERP") is not appropriate because it results in an ERP that is substantially lower than any of the corroborating benchmarks. The Board should not limit itself to one specific method of calculating an equity risk premium; rather, it should consider the results produced by multiple approaches in order to generate a range of reasonable results from which it may select an appropriate ERP. This process requires the exercise of informed judgment, and is necessarily imprecise and imperfect. However, the Board can improve the accuracy of its ERP estimate by reviewing market evidence and considering expert opinion. As the Board observed in its Draft Guidelines, the current ROE Formula limits the OEB's ability to exercise its informed judgment. This concern argues for a more frequent review of the Formula results to ensure that the ROE Formula continues to reflect investor expectations and return requirements.

i. How does OEB determine the ERP?

After considering the evidence presented by numerous interested parties, the Board determined that the appropriate risk premium for Consumers Gas, at a long Canada yield of 7.25%, was 340 basis points. The Board ultimately reduced this amount by 35 basis points due to timing differences related to implementation of the settlement proposal in regard to the implementation of the ROE Formula results.[46] However, the Board did not explicitly indicate how it arrived at an equity risk premium of 340 basis points.

In the Board's 2002 review of its ROE guidelines, it explained how the equity risk premium was derived as follows:

> The equity risk premium test is also designed to measure the cost of equity capital from the capital attraction perspective. It relies on the assumption that common equity is riskier than debt and that investors will demand a higher return on shares, relative to the return required on bonds, to compensate for that risk. The premium required by an investor to assume the additional risk associated with an equity investment is taken to be the difference between the relevant debt rate, usually the

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46 Ontario Energy Board, E.B.R.O. 495, Decision with Reasons, Consumers Gas, August 21, 1997, at 136-137.

yield on long-term government bonds, and some estimate of the stock's cost of equity. The recommended cost of equity value under the equity risk premium approach is therefore usually computed as the sum of the test-period forecast for the government and the utility-specific risk premium the analyst has estimated based on historical equity risk premium evidence and forward-looking considerations.[47]

ii. Board's comments regarding ERP in 1997 Draft Guidelines

The OEB's Draft Guidelines contained several important observations about the equity risk premium, which have shaped the Board's policy on cost of capital since the ROE Formula was adopted. These include:

> A utility's test year ROE will consist of the projected yield for the 30-year long Canada bonds plus an appropriate premium to account for the utility's risk relative to long Canada bonds. The resulting ROE should not compromise the utility's financial integrity and should be consistent with the returns being earned on other regulated utilities of similar risk. However, it will not necessarily be consistent with the returns being earned by comparably risky non-regulated enterprises. (page 29)
>
> The Board recognizes that while the equity risk premium test is conceptually quite simple, the quantification of the test can be rather complex. Factors such as business cycle trends, inflationary expectations and changing investor requirements result in a significant variation with respect to how the risk premium test is derived. Clearly, the use of informed judgment is required, and it is because of this element of judgment that expert witnesses regarding the test's conclusions often differ. (page 30)
>
> The Board anticipates that, in assessing the initial implied risk premium and appropriate ROE for Consumers Gas, interested parties may consider all relevant issues with respect to the application of the equity risk premium test. This may include matters such as the nature of the relationship between interest rates and the implied risk premium, the need to adjust "bare bones" ROE for financing flexibility, and the riskiness of Consumers Gas' equity relative to long Canada bonds and to the overall stock market. In addition, parties may wish to consider the results of the DCF test and the Comparable Earnings test as a means of checking the validity of the equity risk premium test results. (page 30)

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47 Ontario Energy Board, RP-2002-158, In the Matter of Applications by Union Gas Limited and Enbridge Gas Distribution, Inc. for a Review of the Board's Guidelines for Establishing Their Respective Return on Equity, Decision and Order, issued January 16, 2004, at paragraph 44.

> Applying ERP unquestionably involves judgment and subjectivity; however, it is the Board's view that the requirement for ongoing subjective judgments can be limited by the careful initial setting of the formula. Once risk premiums are determined, the only change would be to the forecast bond rate. In the Board's view, the risk premiums will only change if there is a significant change in the utilities' business operations or capital structure, or if there is a material change in the markets. While it is not the Board's opinion that the ERP is a more accurate method of determining the ROE, the Board believes that, in comparison with the other ROE tests, the results of the ERP approach generally require fewer judgmental adjustments. (page 27)

There are a number of different methods to estimate the risk premium that equity investors require. Subtracting the forecasted yield on the Government of Canada long bond from the results of cost of capital analyses, derived by alternative methods, would result in an implied ERP. Several investment banks have published research reports indicating that the equity risk premium has risen significantly to reflect investors' risk aversion. J.P. Morgan, for instance, recently estimated the current equity risk premium as being between 8 and 10 percent. The average spread between government bonds and A-rated corporate bonds has been 2.66 percent in the U.S. and 2.60 percent in Canada from August 2008 through August 2009. Therefore, one would expect the equity risk premium to be significantly higher than the credit spread in order to reflect the additional risks associated with equity ownership.

iii. Adjusting the ERP Going Forward

Concentric has evaluated several options for updating the ROEs resulting from the Board's determination, factoring in three primary considerations:

- The probability of meeting all three elements of the fairness standard
- Regulatory efficiency
- Transparency

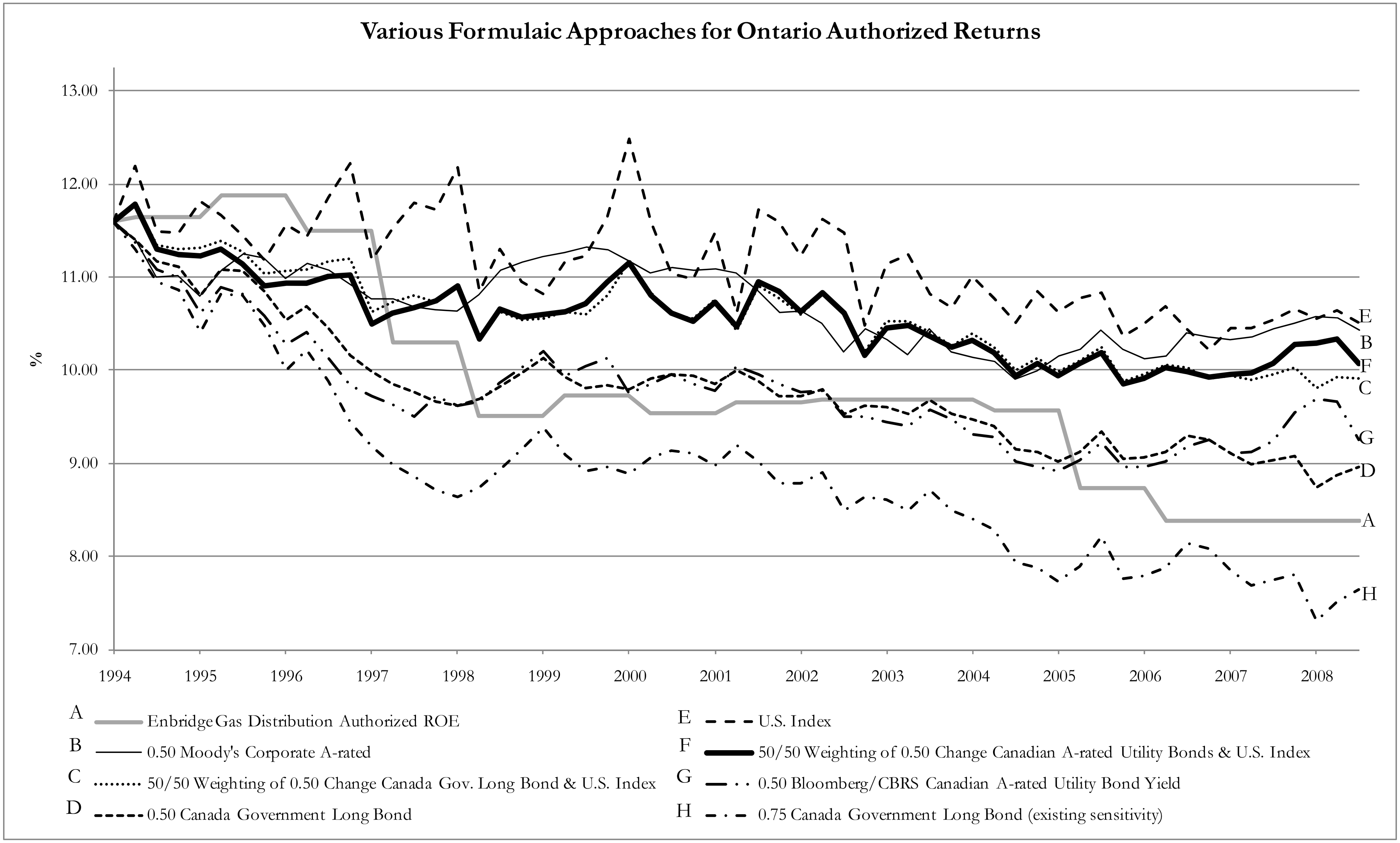
The options considered were:

1. Recalibrate the Formula to yield a generic ROE consistent with the ROEs we have estimated, and re-estimate the Formula, lowering the sensitivity to changes in interest rates (with an off-ramp tied to an appropriate measure, such as ROE awards in other jurisdictions).

2. Create a new ROE adjustment mechanism, indexed to ROE awards for an appropriate group of comparable utilities, bond yields, or a combination of the two.
3. Reset ROE, with no prescribed rate hearing schedule, but hearings may be requested by either the Board or utility with "x" days notice.

In our opinion, option 3, above, provides the greatest assurance of meeting the fairness standard over time, but it is less likely to satisfy the Board's objective for regulatory efficiency. To help examine the remaining alternatives, we have performed a "back cast" analysis using Enbridge's 1994 allowed ROE of 11.60 percent as our starting point.

Figure 12: Back Cast Analysis



As demonstrated in Figure 12, these methods yield results over time that may diverge considerably. By mid-2009, the difference between utilizing a factor of 0.50 on government bond yields versus the 0.75 factor currently in effect would have resulted in a 131 basis point difference in itself. As mentioned previously, our analyses suggest that the factor on government bond yields should be lower than 0.50 and more in the range of 0.40. We have illustrated a variety of combinations as if they had been implemented in 1994, the year of adoption by the NEB and the last fully litigated case before the 1997 base and Formula were applied in Ontario. First, we have illustrated the outcome of the present Formula which results in the lowest level of ROEs on the chart (at the far right) due to its high sensitivity to falling government bond yields. The second lowest line on the chart is Enbridge Gas Distribution's allowed ROE. Next, we depicted what the result would have been by reducing the sensitivity to interest rates, applying a coefficient of 0.50 to the change in government bond yields. That result is represented by the third lowest line on our chart. In our opinion, neither of those approaches, based solely on the change in government bond yields, provides adequate premiums over corporate borrowing costs or returns commensurate with investment alternatives of comparable risk.

To compensate for these shortcomings, we have equally weighted the result of the government bond yield approach (using a coefficient of 0.50) with an index representing the change in North American litigated allowed returns.[48] This index provides a directional measure of comparability with other North American utilities. Though this index is currently made up of predominantly U.S. authorized returns, as litigated returns are available in Canada they should be considered in this index. This methodology would have resulted in the fourth line from the top on the figure above, had it been implemented in 1994. We have also computed the Canadian ROE based entirely on the North American index. That result is generally represented by the top line on Figure 12.

As the disparity between corporate bond yields and government bond yields becomes more pronounced in the current economic crisis, it is evident that government bond yields are an inadequate index for ROE as a single factor. As demonstrated in response to Question 11, corporate borrowing costs may diverge markedly from government bond yields. This failing sheds

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[48] This index was derived by determining the weighted average of gas and electric utility ROE decisions per RRA for the period under review; and dividing that average by the average of the previous period. The resulting index was applied to the previous year return in Canada to obtain the current year return.

light on the benefits of an ROE formula that incorporates credit risk into the equation. Accordingly, we have analyzed an approach based on Moody's Corporate A-rated bond yields (using a coefficient of 0.50 applied to the change in bond yields); and an approach based on 0.50 of the change in the Canadian A-rated 30-year Utility Bond as published by Bloomberg.[49] Lastly, we have weighted the Canadian A-rated 30-year utility bond index (Bloomberg) 50/50 with the litigated return index. That result is the heavy line on the chart and our recommended formula. In our opinion, the similarity and high correlation between U.S. and Canadian equity markets (shown below), debt markets (illustrated in 11), and government bond yields (illustrated in Figure 10), is sufficient basis to assume that U.S. utility equities and Canadian utility equities will also move in tandem as they have since 2002.

Figure 13: Comparison of U.S. and Canadian Utility Equity Indices

49 The Bloomberg 30-Year Canadian Utility Bond Yield series is only available for 2002 to present. We have filled in back periods with a CBRS Canadian Utility Bond Index that covers 1994 – 2000. We have estimated the period from 2000 to 2002 based on the historical relationship between Canadian government bond yields and the A-rated Canadian utility yields.

Observing the back cast results, one cannot be sure that any of the formulaic approaches would satisfy the fairness standard over time. To provide a safeguard against the formula resulting in deficient returns in a period of unanticipated capital market circumstances, we recommend that the ROE mechanism be reviewed annually by the Board against suitable market indicators as described in our responses to Questions 17 and 19 (government and corporate bond yields, ROE awards in litigated jurisdictions, etc.). As indicated previously in our response to Question 8, in Concentric's view, it is important to provide flexibility to address problems with the formula as they arise and to make adjustments as the Board deems merited. Additionally, formal reviews should be conducted every 3 – 5 years with a complete cost of capital analysis to recalibrate ROEs.

The recommended formula adjustment would work as described in Appendix G.

IX. ADOPTION OF A DEAD-BAND AND/OR TRIGGER MECHANISM

Question 14: Should the Board adopt a dead band? If so, what should the range of the dead band be?

<u>Response</u>

In the context of the OEB's ROE determination, as suggested in the Board's preamble, a deadband might be adopted where approved ROEs remain in effect until a deadband is reached. In Concentric's view, an implicit deadband exists with most ROE determinations. Once set by a commission, the ROE remains in effect until either a re-set date is reached (such as the typical annual formula adjustment prevalent in Canada) or in the U.S. where the utility or Commission can initiate a rate hearing when circumstances warrant. In the interim, the utility and customers bear the risk that market circumstances have changed, warranting a change in ROE.

Deadbands used within a certain range promote regulatory efficiency by not litigating ROE. With a formula, this efficiency could be further realized by setting narrow deadbands that balance the desired goal of improved efficiency with the interests of shareholders and ratepayers. Recognizing that the ultimate objective is a fair return, a dead band is viable as long as all three tests are met: 1) comparable investment; 2) capital attraction; and 3) financial integrity. Utility investors are accustomed to earnings swings within a relatively narrow band. This assumes the base ROE is fair, the expected deviation from the allowed return is neutral and fluctuations do not jeopardize the financial integrity of the utility. Though Concentric does not recommended a deadband in its formula, we accept that a deadband has the benefit of regulatory efficiency, and is appropriate when regulatory expediency can be optimized without sacrificing a fair return. On balance, if the Board adopts Concentric's recommended approach, we do not believe a deadband is required by the Formula, but may be a useful tool for promoting performance based regulation (PBR) objectives.

Question 15: Should the Board adopt trigger mechanism(s)? If so, how often should the Board review the methodology?

<u>Response</u>

Observing the back cast results in Figure 12, one cannot be sure that any of the formulaic approaches would satisfy the fairness standard over time. To provide a safeguard against the formula resulting in deficient returns in a period of unanticipated capital market circumstances, we recommend a routine monitoring process (no less frequent than annually) that incorporates those factors identified in Questions 16 through 19 of this Document and establishes specific thresholds for identifying changed market conditions prompting a benchmark study of the adequacy of returns. Additionally, we believe a formal review proceeding should be implemented every three to five years, where ROE may be recalibrated and reset, among other things. Absent these review processes we recommend, it is appropriate to set rails for the Formula to trigger a formal review of the Formula. Appropriate trigger mechanisms may include a 150 to 200 basis point symmetrical ceiling and floor established from the starting ROE for each utility, or a specified deviation from average North American litigated allowed returns. Concentric suggests an overall review of the entire ROE framework and adjustment mechanism every three to five years.

X. METHODS TO CORROBORATE RESULTS PRODUCED BY THE FORMULA

Question 16: What is the appropriate test(s) to ensure the FRS is met (e.g., corroborating results for reasonableness relative to benchmarks or through other methods)?

<u>Response</u>

In order to definitively determine whether the fair return standard is being met, a cost of capital study is required, such as that presented in Appendix F. The required return on common equity, using multiple analyses, such as the DCF and CAPM, will indicate whether an equity risk premium approach is accurately tracking the cost of common equity. In addition, comparable returns analysis, changes in the level of corporate debt costs, as well as the level of yield spreads and the comments of professional equity analysts should corroborate or suggest that the Board's Formula does, or does not, continue to reflect the cost of common equity capital for Ontario electric utilities and gas utilities.

Recognizing that the Board desires an approach that is efficient to administer, it is relatively straightforward for Staff to update DCF and CAPM studies using readily available information. If the Formula return deviates significantly from the average results of the DCF and CAPM studies for a specified period of time, the Formula should be re-opened and a possible re-basing of the Formula should be considered. Similarly, if a utility has difficulty raising capital on reasonable terms, the Board should consider that special circumstances exist that would dictate either deviating from the Formula or re-basing the Formula as needed.

Question 17: What information might the Board need to definitively determine that market conditions are having an effect on the variables used by the Board's cost of capital methodology?

<u>Response</u>

It should be noted that market conditions always affect cost of capital variables. The question is whether the Formula and variables used by the Board continue to adequately reflect the changing cost of capital. As stated in response to Question 16, to definitively determine the effect of market conditions on the cost of capital variables used by the Board, a cost of capital study using multiple approaches and inputs is required. However, equity analyst reports, comparable litigated returns for utilities in other North American jurisdictions, and comparisons of the equity risk premium implied by the Formula to those projected by analysts, all provide meaningful input into whether a change in market conditions is skewing the results of the Formula in one direction or the other.

XI. USING FINANCIAL MARKET INDICATORS TO TEST REASONABLENESS OF RESULTS

Question 18: Should the Board consider monitoring indicators like these on an on-going basis to test the reasonableness of the results of its cost of capital methodology?

Response

Yes. The Board should remain an informed participant and apprised of trends in capital markets through practical routine monitoring of those factors mentioned in our responses to Questions 16 and 17. Furthermore, a regulatory process that provides sufficient flexibility for stakeholders to request a review of the Formula should enable an informed and constructive dialogue between regulators and stakeholders to assess the reasonableness of the results from the Board's cost of capital methodology. Lastly, Concentric is of the opinion that the focus of the monitoring effort should not be on whether market conditions are having an effect on the variables used by the Board's cost of capital methodology, but on whether the three required standards for fairness are being met. As indicated in our response to Question 17, market conditions do affect cost of capital variables; it is only when those conditions result in unfair returns for utilities that this is of concern.

Question 19: What other key metrics used by financial market participants to determine whether financial market conditions are or are not "normal" might the Board consider?

Response

As noted in the response to Question 9, Concentric believes that the allowed ROE must satisfy the Fair Return Standard regardless of whether current market conditions are deemed to be "normal." However, Concentric understands the Board's desire to have some indicators that would help it to monitor financial market conditions. In that regard, there are some basic indicators that might provide the Board with an early warning signal that it should conduct a more thorough DCF or CAPM analysis to compare the results of those approaches against those produced by the ROE Formula. These indicators would include things such as changing credit spreads between corporate and government bonds, changes in equity market volatility indices, credit rating changes for Ontario utilities, divergence between Canadian and U.S. debt and equity market indices, or shifts in price/earnings ratios and dividends yields. Generally if there is a shift in the financial markets, Concentric would expect most, if not all, of these indicators would send the same signal. In conclusion, Concentric's view is that the Board should not attempt to modify or fine tune the Formula results based on these market indicators, but they may provide the Board with valuable insight about major disruptions in financial markets that would impact the cost of equity or debt capital.

XII. APPENDICES

Appendix A: Capital Budgeting and Implications for the Comparable Return Standard

The Fair Return Standard encompasses three tests: (1) capital attraction, (2) financial integrity, and (3) comparable return. In applying the comparable return standard a regulator ought to be aware of the decision-making rules that are used in capital budgeting by companies when they decide which capital investments to make. A common assumption in regulation is that companies in a competitive market cannot earn more than their cost of capital, and regulators generally attempt to replicate that assumption about competitive markets when they set the allowed rate of return for regulated companies. For example, the CAPM and DCF approaches are designed to estimate how much the marginal investors expect to earn when they buy or sell common stocks in the market, and that result is considered to be the cost of capital. However, the assumption that companies cannot earn more than their cost of capital misstates the relevant economic theory which actually holds that the *marginal* investment in a competitive market should be unable to earn more than its cost of capital. It is quite common for highly competitive companies to earn more than their cost of capital on the average dollar invested. In fact, standard textbook capital budgeting rules suggest that a company should not invest in a project that is expected to earn no more than its cost of capital. Nevertheless, regulators often use the results of CAPM, DCF or ERP analyses to set the allowed rate of return equal to the marginal cost of capital without regard for the earnings available to the average investment of comparable risk, or the rules that are employed in making capital budgeting decisions. As this Appendix explains, a proper application of capital budgeting principles requires that the allowed rate of return should be set somewhat higher than the marginal cost of capital in order to meet the comparable return test.

i. Capital Budgeting Techniques

1. Net Present Value and Internal Rate of Return

A corporation determines whether to invest in a particular capital project based on whether it is expected to have a Net Present Value ("NPV") higher than the company's marginal cost of capital. Another method is to calculate the Internal Rate of Return ("IRR") for the project, which is the average annual rate of profitability for the project.[50] If the project is expected to generate returns

[50] The IRR is the discount rate that gives a NPV equal to zero.

that exceed the firm's marginal cost of capital, then it will add economic value to the corporation. Standard financial theory indicates that:

> "… we have two equivalent decision rules for capital investment.
>
> 1. *Net Present value rule.* Accept investments that have positive net present values.
> 2. *Rate-of-return rule.* Accept investments that offer rates of return in excess of their opportunity costs of capital."[51]

Both of these rules require that an investment must be anticipated to earn more than its cost of capital in order to be acceptable. Beyond this bare minimum of acceptability, when the corporation's capital budget is constrained, it generally ranks and prioritizes the various projects according to their NPV or anticipated IRR. In general, those capital projects with the highest NPV or IRR should be pursued first because they maximize the value of the firm.

2. Hurdle Rate

In financial theory, a "hurdle rate" is the minimum rate of return required for accepting a capital project. Stated another way, it is the cutoff or screening rate for capital budgeting purposes. The general decision making rule is that if a project's internal rate of return exceeds the project's hurdle rate, then the financial manager should accept the project. If not, then the project should be rejected.[52]

3. Returns Available on Alternative Investments

The concept of ranking capital projects based on whether they meet a specified hurdle rate is illustrated in Figure 1. A project in that figure is considered to add economic value to the firm if the projected IRR exceeds the cost of capital. In the figure below, Projects A through C have IRRs that are higher than the hurdle rate and would be acceptable from a financial theory perspective. Conversely, because Projects D and E have IRRs equal to or lower than the hurdle rate, basic textbook theory suggests that those projects should be rejected.

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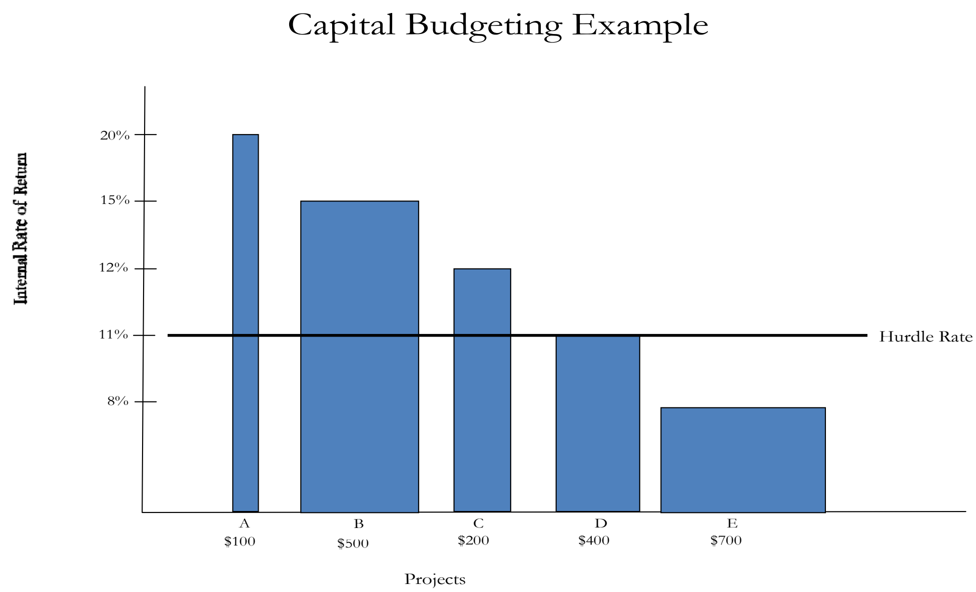
51 R. Brealey and S. Myers, *Principles of Corporate Finance*, 2nd ed., McGraw-Hill (1984), p. 13.

52 Business Financial Management, "Capital Budgeting," published by The Dryden Press, Philip L. Cooley and Peyton Foster Roden, at 330.

Figure 1: Ranking Capital Projects by Internal Rate of Return



Although projects A, B and C all pass the hurdle rate test, a company might not pursue all three projects if other constraints apply. For example, if managers have time to work on only two projects, then project C might be rejected. Similarly, if the company's cash flow and balance sheet allow it to comfortably spend no more than $600 million on capital projects in the next year, then project C might be rejected.

4. Relevance of Capital Budgeting Concepts for Applying Regulatory Standards

Investors in regulated utility assets adhere to the same capital budgeting process in terms of ranking capital projects according to their expected profitability. However, because regulators generally attempt to set the rate of return on utility assets at a level equivalent to the utility's cost of capital, utility investments would be equivalent to project D in the above example. Project D satisfies the rate of return goal pursued by most regulators, but capital budgeting theory says that a company should reject such a project. At best, an allowed rate of return equal to the cost of capital (i.e., the hurdle rate) should make investors indifferent as to whether investments are made to provide utility services to the public. In order to correctly apply the comparable earnings standard, a project should have an allowed rate of return comparable to those of projects A, B and C, which all *exceed* the hurdle rate or cost of capital. Therefore the allowed rate of return should be somewhat higher than the cost of capital.

The implication for Ontario is that the OEB should consider the returns the company could earn on the equity portion of the book value of its capital investments if it were operating in a competitive unregulated or comparable regulated environment elsewhere. One measure of such returns is suggested, in a report concerning Enbridge in which CIBC Capital Markets conducted a valuation analysis of Enbridge in which the analysts "assumed a 12% after-tax, unlevered ROE, which is a typical hurdle rate (and typically achieved) for Enbridge."[53] This suggests that returns currently allowed in Ontario are far below any sort of reasonable comparable earnings. Nevertheless, because the utility has an obligation to serve customers within its defined service territory, it must pursue capital projects that are necessary for it to satisfy that obligation to serve, even when capital budgeting theory, and the comparable return standard, both indicate that the project should be rejected.

53 CIBC World Markets, Enbridge Inc., *Equity Research Company Update*, December 17, 2008.

Appendix B: Capital Structure Theory and Application

i. Capital Structure Theory

1. Capital Structure Concepts

a. Relationship between capital structure and cost of common equity

The cost of common equity capital and the fair rate of return depend in part on the company's capital structure. Other factors being equal, firms with lower common equity ratios have higher costs of common equity and require higher rates of return to compensate for the additional financial risks to which their shareholders are exposed. Consequently, when a regulator selects a deemed capital structure, that decision impacts the required rate of return on common equity.

Application of capital structure theory indicates that the use of bond rating criteria as the primary determinant of deemed common equity ratios can lead to allowed rates of return on common equity that are inadequate and unfair to the common stockholders. Consequently, when conducting an analysis of the required rate of return on common equity and the appropriate capital structure it is essential to distinguish between enabling a company to: (1) attract common equity on fair and reasonable terms; and (2) maintain investment-grade bond ratings.

b. Effect of Capital Structure on Cost of Doing Business

Most large companies are financed using a mix of debt and equity capital. Debt in the capital structure can provide a low-cost source of funds because the common equity holders shield lenders from a portion of the risks of the company. However, the requirement to pay a fixed level of interest and repay principal as scheduled causes the possibility of bankruptcy or other financial distress to increase as the firm takes on more debt. Financial "leverage" provided by fixed debt payments also tends to translate relatively small fluctuations in a company's operating income into much larger variations in the net income available to common stockholders. When the proportion of debt is increased beyond some level, both lenders and stockholders require greater rates of return to compensate for the greater risks involved. In theory, there is an optimal range of equity ratios that minimizes the overall cost of capital of a company.

c. Important Factors for Determining Appropriate Capital Structure

The amount of debt that is economical for a firm depends on its business risks and the perceived probability that it could experience unexpected difficulties that would render it unable to meet its debt obligations. Although firms in the same industry generally tend to have similar business risks, there is often a general, very broad range of equity ratios associated with companies in particular industries. Firms in the same industry have different capital structures for many reasons. For example, within a given industry, there may be wide differences in the vintages of capital and operating strategies of individual companies. Another important factor is the quality of a firm's earnings in terms of cash flow and continuing operations. **When all factors are considered, the managers of a company are usually in the best position to evaluate the prospective risks and operating needs of their company and determine the most appropriate capital structure.**

Another important factor is the transaction cost of raising new capital. In order to borrow funds from outside sources a company typically pays issuance costs that are close to one percent of the amount borrowed. In contrast, raising new common equity funds from outside sources generally involves flotation costs that are 3-5 percent of the amount of capital raised. In addition, on a percentage basis, flotation and issuance costs generally are proportionately lower for larger issues. The higher flotation costs associated with raising equity capital from external sources means that, up to a point, it is less expensive to issue debt for as much external financing as possible before turning to the external equity markets.

Different companies also have different patterns of needs for financing. A company might take on large amounts of debt to finance new projects, but then pay down its debt and increase its equity ratio over time after the project is in service. **When a company's debt ratio is high, its financial flexibility is restricted.** This means that its ability to undertake additional projects is limited and it may not be able to refinance its debt or raise new capital if adverse circumstances arise.

Thus, when one considers financing costs and the often uneven pattern of capital investments, there may be times when achieving the target capital structure may not be as desirable as minimizing the issuance costs that the firm incurs as it operates on a dynamic basis. A well-managed company might reasonably maintain a relatively high equity ratio for extended periods of time and then undertake a large amount of additional debt to finance a new project. The important point is that wide differences in capital structures exist within any given industry from time to time and a **determination of the "appropriate" capital structure for a particular company should not be made in a vacuum which ignores that company's unique history, business needs and circumstances.**

2. Modigliani-Miller and the Optimal Capital Structure

The cost of capital for a company depends upon both its business risks and the amount of debt in its capital structure. At one point in the development of the theory of capital structure, Professors Modigliani and Miller (1958) questioned why the mix of debt and equity in the capital structure should have any effect upon the overall weighted cost of capital of the firm. They argued that the risks and operating income of a company should be the same regardless of how the company is financed. They reasoned that any change in capital structure would merely shift the risks and rights to operating income between lenders and shareholders without changing the overall risks or income of the company and therefore should have no effect upon the overall cost of capital. This conjecture that capital structure theoretically should not affect the overall cost of capital of a company is known as the Modigliani-Miller Theory.

The Modigliani-Miller Theory set off a great deal of research in finance and it is now widely agreed that the theory failed to recognize several important effects of capital structure decisions. First, the theory incorrectly assumed that operating income is split only between lenders and shareholders. However, the government, through corporate income taxes, typically is a third claimant on a portion of the company's operating income. Because interest payments are tax deductible, but dividend payments generally are not, as a company takes on more debt it increases the amount of its tax deductions and reduces the share of operating income claimed by the government. Thus, the size of the government's share of income depends upon the capital structure of the firm.

Second, Modigliani and Miller originally assumed incorrectly that the business risk and level of operating cash flows of a company are the same, regardless of how the company is financed. However, increasing the amount of debt in the capital structure increases the probability of bankruptcy or financial distress, which would trigger large legal fees and other costs that can greatly reduce the share of operating income available to shareholders and lenders. Large amounts of debt also may have other less-obvious costs to the company such as bond covenant restrictions on its ability to make additional investments and requirements that it maintain higher interest coverage ratios. These restrictions can prevent a company from pursuing profitable new opportunities and may constrain its ability to make capital investments that improve its existing operations. In addition, when a company is in danger of being unable to make interest payments or repay its loans, its suppliers often will refuse to do business with it or require prepayment or other onerous trade conditions. Similarly, customers may refuse to do business with a company in distress for fear that they will not receive their goods. In both instances, **a high debt ratio increases the probability that operating income will be less than expected.**

3. Effects of Leverage on Debt Costs
   a. Why Companies Borrow to Finance Operations

Companies tend to borrow money because the interest rate on loans is less than the return that equity investors require. In addition, because the interest paid on debt generally is tax deductible, a company can reduce its tax liability by relying on debt. However, a higher debt ratio increases the risk that a company could be unable to make interest payments and repay its loans and common stockholders must agree to shoulder a disproportionate share of the risk in order to obtain the benefits of debt financing. **Interest rates on debt tend to increase once a company's debt ratio exceeds a certain level, but the amount of debt that a company can take on before its interest rates begin to increase rapidly is different for different industries, and also different for different companies.**

   b. Importance of Bond Ratings in Raising Capital

Bonds rated BBB (or Baa) or higher are referred to as "investment grade," which means that financial institutions with a fiduciary duty may invest in these low-risk bonds. Many institutional investors in Canada have limits on the proportion of BBB (or Baa) rated debt they are allowed to hold in their portfolios or cannot invest in BBB (or Baa) rated debt at all. The average yields on corporate bonds are progressively higher as the bond ratings decline. **When the bond rating falls below investment grade (i.e., less than Baa), the required interest rate increases markedly as fewer investors are able or willing to purchase lower-rated bonds.**

c. Correlation between Bond Ratings and Interest Rates

Although there is a tendency for companies with the same bond ratings to cluster around similar yields, most companies have yields that are either higher or lower than the average for their bond rating. There are many possible reasons for these variations, but this sometimes occurs when investors perceive that a company has either higher or lower risks than its bond rating would suggest. In fact, a great deal of **financial research has shown that the market yields of bonds are often a better indicator of the risks perceived by investors than the ratings assigned by bond rating agencies.**

4. Effects of Leverage on Equity Costs

Because common stockholders do not make a profit until all of the other obligations of the company are paid, **additional debt obligations in the capital structure increase the probability that the common stockholders will not recover their investment plus a reasonable rate of return.** At moderate debt levels the cost of common equity increases only slightly as additional debt is added to the capital structure. At some point, however, the probability of bankruptcy or inadequate returns begins to rise rapidly and investors require a commensurately large increase in the possible returns in order to compensate for the greater risk.

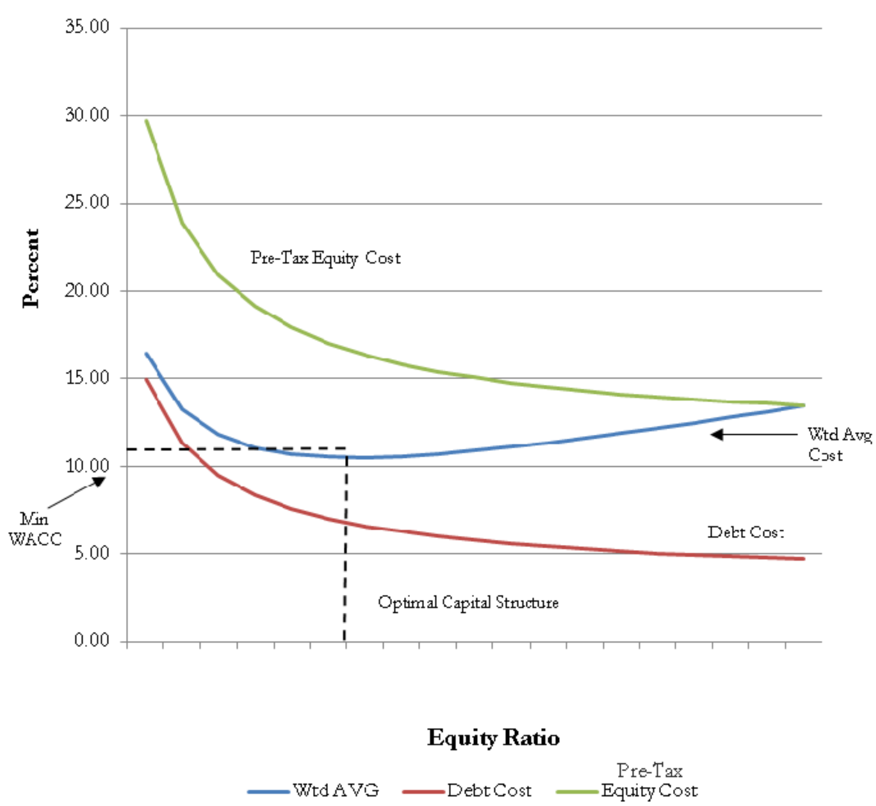
5. Optimal Capital Structure
   a. How Debt and Equity Costs Create Optimal Capital Structure

Greater debt in the capital structure reduces the amount of income taxes that must be paid to the government, but increases the probability of financial distress which can lead to onerous bond covenants, high legal expenses and even destroy a business to the extent that suppliers and customers refuse to deal with a company in financial distress. These countervailing effects – reduced taxes v. higher distress costs – mean that **there is an economic tradeoff associated with increasing the amount of debt in the capital structure and this tradeoff suggests that there is a theoretically optimum capital structure that balances tax costs against financial distress costs.**

Figure 1 shows the optimum capital structure when these tradeoffs are considered. There are two factors involved that cause the weighted average cost of capital to decline in the beginning and then turn upward. First, declining financial risk creates a downward pull on the cost of both debt and equity when the equity ratio is increased. Second, because equity costs more than debt there is an upward pull on the weighted average as an increasing proportion of equity is introduced into the mix. When the equity ratio is small the first factor dominates and the weighted average cost of capital decreases. However, at some point the debt and equity cost curves level out and the second factor becomes dominant. At that point the weighted average cost curve turns upward. **The theoretically optimum capital structure corresponds to the lowest point on the weighted average cost of capital (WACC) curve.**

Generally there is a relatively wide range of capital structures surrounding the lowest point on the WACC curve in which the weighted average cost of capital is essentially the same at every corresponding equity ratio. Although there are small changes in the WACC along the flat part of the curve, a WACC that is less than 25 basis points above the minimum point would be within a reasonable margin of error for a cost of capital study.

Figure 1: Cost of Capital Curves



b. Static and Dynamic Considerations

Important considerations for capital structure decisions fall into two general categories: static and dynamic. Figure 1 depicts the combination of debt and equity that theoretically minimizes the overall cost of capital only if the company is either static (i.e., not changing) or if every source of financing has the same economic costs for the firm. However, dynamic considerations – such as the different costs associated with raising different types of capital and the fluctuating financing needs of the company – mean that **a capital structure that is theoretically "optimal" from a *static* perspective usually is not truly optimal from a *dynamic* perspective at any given point in time.** For that reason, it is common to refer to the static capital structure concept shown on Figure 1 as the "target" capital structure around which a company's actual capital structure should fluctuate in order to efficiently finance an ongoing, dynamic operation. The concept of a dynamically optimal capital structure, generally referred to as the "Pecking-Order Theory," is discussed below.

6. "Pecking-Order" Theory of Optimality

The "Pecking Order" Theory states that it is most efficient for companies to raise as much capital as possible from retained earnings, then to issue debt and, lastly, to issue new common equity. In other words, the dynamic order and pattern of financing is often more important than the need to maintain a static, theoretically optimal cap ital structure. Unlike the concept of a static optimal capital structure suggested by the outgrowth of the Modigliani-Miller theory, the "Pecking-Order" theory relies on real-world dynamic considerations such as the varied timing of the company's investment needs, the transaction costs incurred in raising capital, and the fact that financing decisions convey valuable information to the financial markets. Consequently, **static considerations are useful for establishing a long-run "target" capital structure for a company, but they are not adequate for determining the optimal capital structure for the company at any given point in time.** Taken together, the two theories help explain why particular industries have significantly different *average* capital structures from other industries, but also there often is a large variation in the capital structures of individual firms within the same industry.

ii. Interaction between Capital Structure and Required Return

1. Impact of ROEs and Capital Structure on Financial Metrics and Bond Ratings

Bond rating agencies effectively use both capital structure and return on equity in their credit analyses. They use embedded accounting book values in evaluating the debt and equity ratios of the capital structure, but they also use interest coverage ratios that reflect the rate of return that a company actually earns. The analysis of interest coverage ratios captures the effect caused when one company has lower interest rates or higher equity ratios than another company. Finally, ratings agencies account for differences in operating/business risks through a variety of objective and subjective analyses. However, **bond rating agencies do not explicitly analyze or render an opinion as to whether the allowed rate of return on common equity is fair, just or reasonable.**

2. Relationship Between Bond Ratings and Cost of Equity

The allowed rate of return and the deemed common equity ratio can be used to calculate a pro forma interest coverage ratio, but there is no well-defined theoretical relationship between the cost of common equity and interest coverage tests. Consequently, none of the commonly-used methods for estimating the cost of common equity (e.g., DCF, CAPM, and ERP) relies upon interest coverage ratios. For example, pro forma interest coverage ratios generally are calculated using four variables: the interest rate on debt, the rate of return actually *earned* on common equity[54], the income tax rate and the proportion of debt and equity in the capital structure. None of these variables is the cost of common equity. Moreover, a change in any one of these four variables will change the interest coverage ratio, but the magnitude of the effect on the cost of common equity is indeterminate. In summary, for a given cost of debt and a given tax rate, there are numerous combinations of capital structure and equity returns that will all produce the same interest coverage ratio.

3. Relationship between the Equity Cost Curve and the Interest Coverage Curve

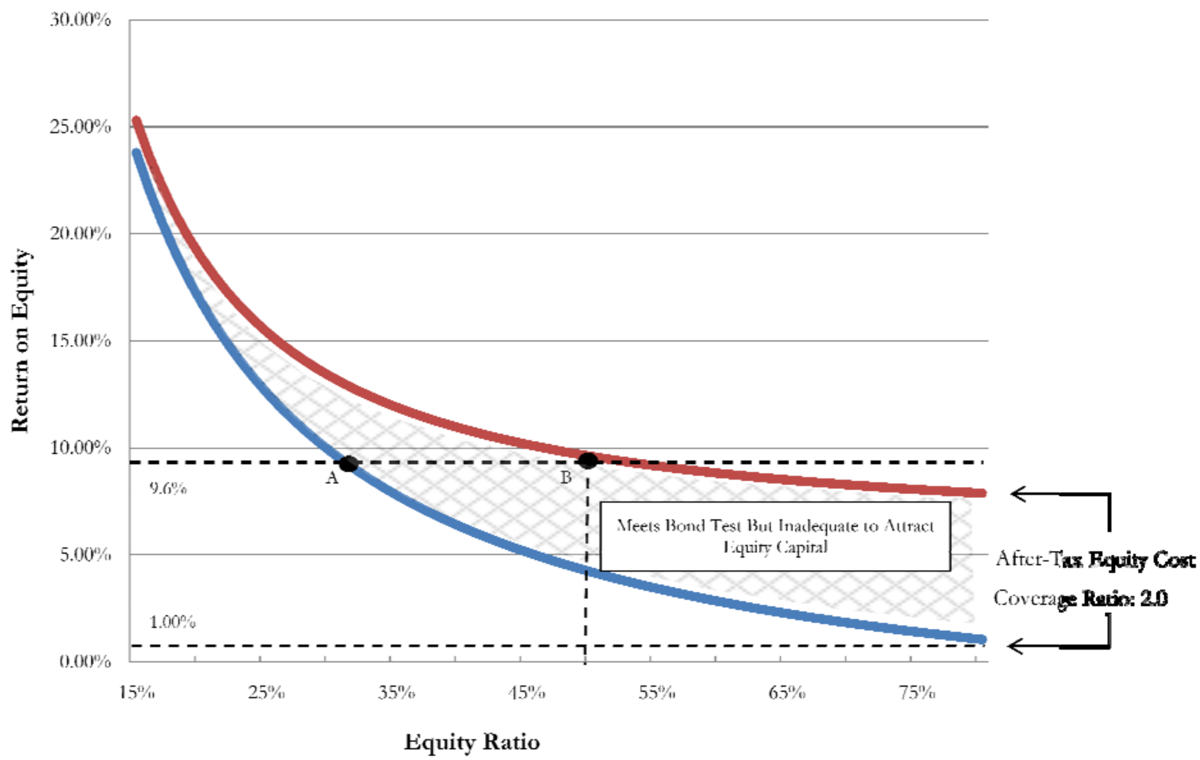
Figure 2 depicts the fundamentally different shapes of the theoretical Equity Cost Curve and the Interest Coverage Curve. In this example, the Equity Cost Curve is drawn with the assumption that any rate of return that is greater than or equal to the cost of common equity capital will achieve a coverage ratio greater than 2.0.

54 The rate of return on common equity used in the calculation is the actual rate of return that the company is expected to earn and is not necessarily the rate of return that investors require as the cost of providing common equity capital.

The difference between these two concepts is shown most clearly by examining the ROE values associated with high equity ratios. If we set equity returns based only on the Interest Coverage Curve, some problems immediately arise. On the right (high equity ratio) side of the Interest Coverage Curve the equity return that achieves a 2.0 coverage ratio is less than the interest rate on debt. For example, notice that according to the Interest Coverage Curve, an allowed rate of return on common equity of *one percent (1.0%)* will be sufficient to achieve an adequate bond rating if the equity ratio exceeds approximately 80 percent. However, **basic finance theory says that the cost of equity is always greater than the cost of debt.** When debt is yielding 6.0 percent, as this example assumes, it is obvious that no one would consider investing common equity in an enterprise that has an expected ROE of one percent.

In Figure 2, the shaded area between the two curves represents the area in which the capital structure-ROE combination is sufficient to produce an adequate bond rating, but is inadequate to attract common equity capital on reasonable terms. Thus, **it is critical to distinguish between bond analyses and common equity analyses.**

Figure 2: Difference Between Bond Coverage and Cost of Equity



A: Proxy Co. ROE, associated with Proxy Co. Eq. Ratio

B: Proxy Co. ROE, associated with Eq. Ratio that gives 2.0 Coverage Ratio

4. Cannot Derive Reasonable Equity Ratios from Interest Coverage Ratios

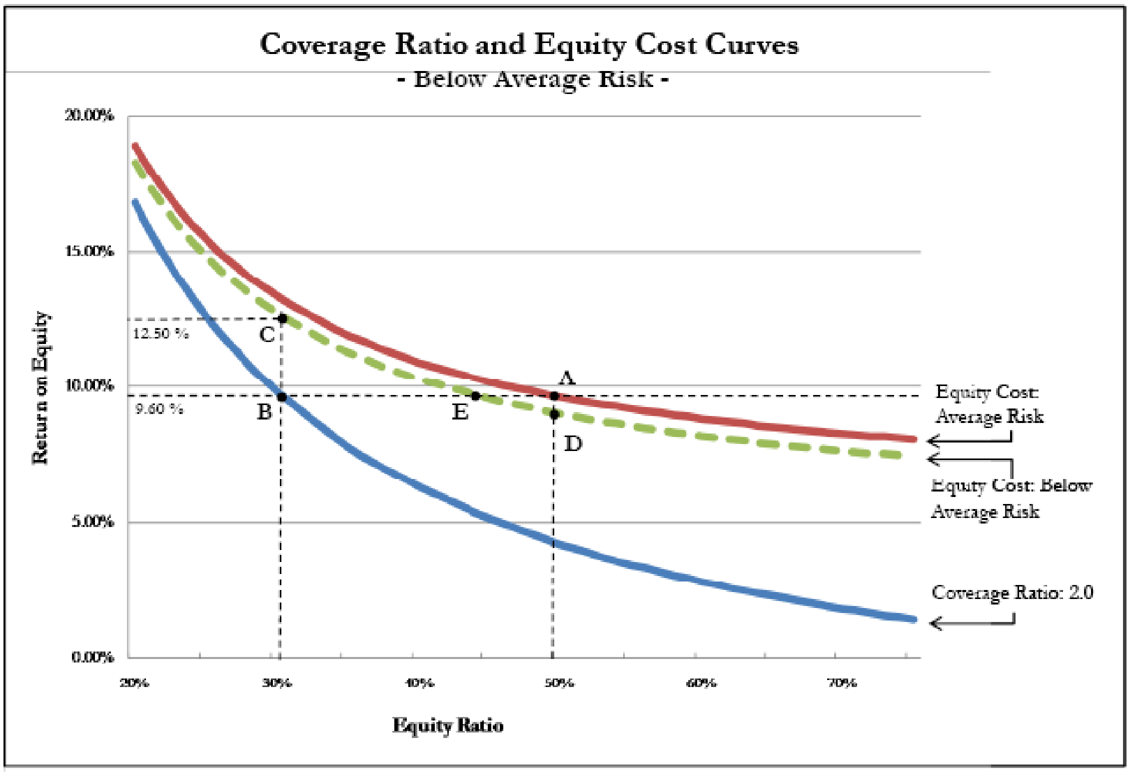
Although an allowed ROE and deemed equity ratio must be adequate to attract debt, as delineated by the Interest Coverage Curve, the correct deemed equity ratios must be determined by applying analytical concepts associated with an Equity Cost Curve. Figure 3 illustrates the conceptual analysis that should be employed if one wants to start with an average ROE and capital structure for a diverse proxy group and then attempt to infer the correct ROE and deemed capital structure for a utility that has below-average risk.

The top curve shown on Figure 3 is the illustrative Equity Cost Curve for the average utility in the proxy group. The middle curve, shown as a dashed line, is the Equity Cost Curve for a utility that has below-average *business* risks. And, the bottom curve is the Interest Coverage Curve for a utility with below-average business risks.

If a rate of return analysis of a group of proxy companies indicates that the cost of common equity is 9.6 percent when the average company has a 50 percent equity ratio, that information would correspond to point "A" on Figure 3. Because point "A" was determined using a cost of equity analysis, it is presumed to be somewhere on the Equity Cost Curve for a hypothetical utility with average risks.

A utility with below-average risks should be on a different Equity Cost Curve that is essentially parallel to, but below and to the left of, the average curve. In Figure 3 the dashed curve represents the Equity-Cost Curve of the below-average utility.

Figure 3: Coverage Ratio and Equity Cost Curves



A: Proxy Co. ROE, associated with Proxy Co. Equity Ratio

B: Proxy Co. ROE, associated with Equity Ratio that gives 2.0 Coverage Ratio

C: Low Risk ROE, associated with same Equity Ratio as point “B”

D: Low Risk ROE, associated with Proxy Co. Equity Ratio

E: Proxy Co. ROE, associated with Low Risk Equity Ratio

Conceptually, there are several ways that one might attempt to use point “A” to determine the required combination of ROE and deemed equity ratio for a utility that has below-average business risks. For example, if one uses point “A” to determine that 9.6 percent is a required ROE for average utilities with a 50 percent equity ratio, one could determine that a below-average utility could achieve an adequate bond rating by moving to point “B” on the Interest Coverage Curve. At point “B” the deemed equity ratio could be approximately 31 percent, but in all likelihood the required ROE would be considerably above point “B.” In this example, for utilities with below-average risk, the required ROE would be at point “C” on the Equity-Cost Curve. As shown, an appropriate allowed ROE likely would not fall on both the Interest Coverage Curve and the Equity Cost Curve simultaneously and the Equity Cost Curve would be substantially above the Interest Coverage Curve. In this example, a 31 percent equity ratio would correspond to a required ROE of approximately 12.5 percent for a utility with below-average business risks.

Appendix C: Proxy Groups

In situations where common stock is not publicly traded, or the common stock that is traded does not represent the subject utility, one cannot calculate an ROE based on public market statistics. Instead, one can select a proxy group that best represents the financial and operating risks of the subject company to make a reasonable estimate of the target company's ROE. Three comparable groups have been established to benchmark Ontario utilities' ROEs for each sector: 1.) a U.S. natural gas distribution proxy group; 2.) a U.S. electric distribution proxy group; and 3.) a Canadian utilities group.

To select the group of comparable natural gas utilities, we began with the population of companies classified by Value Line as "Natural Gas Utility" and "Electric Utility". Value Line lists 12 natural gas utilities and 54 electric utilities to which the following screens were applied to best reflect the financial characteristics of the Ontario natural gas utilities. The criteria are as follows:

1. All are currently publicly traded and paying dividends as recent market data must be available to calculate the DCF and CAPM;
2. Utilities with S&P credit ratings similar to that of Ontario's natural gas distribution utilities, that is greater than or equal to BBB and less than or equal to A+;
3. Utilities with greater than 60 percent regulated operations, as measured by the percentage of regulated utility revenue to total consolidated revenue for 2006 through 2008;
4. At least 60 percent of regulated revenue was derived from natural gas distribution operations for 2006 through 2008; and lastly
5. Excluded any utility that is currently the target of an acquisition or merger since the stock price may not be representative of its underlying utility operations.

These screening criteria resulted in the following seven utilities:

1. AGL Resources Inc.
2. CenterPoint Energy, Inc.
3. Piedmont Natural Gas Company, Inc.
4. Sempra Energy
5. South Jersey Industries, Inc.
6. Southwest Gas Corporation

7. Vectren Corporation

We have removed CenterPoint Energy, Inc. from the proxy group because even though it met our screen of 60 percent regulated natural gas revenue (at 62.08 percent), it's regulated natural gas utilities only contributed 18.65 percent to the operating earnings of the company. It's regulated electric income contributes a greater share of the consolidated regulated earnings of the company at 57.45 percent. As such, it is properly excluded from the gas proxy group. The final natural gas distribution group consists of the following six companies:

1. AGL Resources Inc.
2. Piedmont Natural Gas Company, Inc.
3. Sempra Energy
4. South Jersey Industries, Inc.
5. Southwest Gas Corporation
6. Vectren Corporation

Screening criteria results and financial statistics for the proxy groups are provided in Exhibit Concentric-01 and Exhibit Concentric-02.

For our comparable group of electric distribution utilities, we began with the population of companies classified by Value Line as "Electric Utility". Value Line lists 54 electric utilities and similar to the natural gas distribution group, the following screens were applied to best reflect the financial characteristics of the Ontario electric distribution utilities. The criteria are as follows:

1. All are currently publicly traded and paying dividends as recent market data must be available to calculate the DCF and CAPM;
2. Only low-risk A-rated utilities, eliminating any companies with an S&P credit rating lower than A-;
3. Utilities with greater than 60 percent regulated operations, as measured by the percentage of regulated utility revenue to total consolidated revenue for 2006 through 2008;
4. At least 60 percent of revenue was derived from regulated electric operations for 2006 through 2008; and lastly
5. Excluded any utility that is currently the target of an acquisition or merger since the stock price may not be representative of its underlying utility operations.

These screening criteria resulted in the selection of the following eight companies for the comparator group:

1. CH Energy Group, Inc.
2. Consolidated Edison, Inc.
3. DPL Inc.
4. Duke Energy Corporation
5. FPL Group, Inc.
6. MGE Energy, Inc.
7. NSTAR
8. Southern Company

Screening criteria results and financial statistics for the proxy groups are provided in Exhibit Concentric-01 and Exhibit Concentric-02.

Given that Ontario's electric distribution utilities operate in a restructured competitive market, they do not own regulated generation assets. However, seven of the eight utilities in our U.S. electric distribution utility proxy group own some form of regulated generation. Of the seven utilities that own generation, three companies purchase a large portion of their load from third-party generators while four are considered vertically integrated utilities that generate, transmit and distribute electricity for their customers. To eliminate companies with any generation holdings would eliminate all but one utility from our group. As such, we have estimated the effect of generation on a utility's authorized ROE using regression analysis. Our regression equation is as follows:

$$ROE = \textit{Constant} + \textit{U.S. Gov. 30-year Bond} \bullet x_1 + \textit{Moody's Utility A-rated Spread} \bullet x_2 + \textit{\% Generation} \bullet x_3 + \textit{Natural Gas Dummy Variable} \bullet x_4$$

U.S. authorized ROE data was sourced from Regulatory Research Associates and includes electric and natural gas rate case decisions from 1993 through 2009. Each authorized ROE is paired with the corresponding average U.S. government bond yield for the six months (180 trading days) preceding the decision date in order to capture the bond yield that was considered during the proceeding. The Moody's Utility A-rated Spread is calculated in a similar fashion and represents the six-month average spread between the Moody's Utility A-rated Bond Index and the U.S. government 30-year bond. The percent generation applies to electric utilities and represents the percent of total energy sources generated by a particular utility for the year in which each rate case was decided. The source of this data is the FERC Form 1, page 401a and is net generation divided by total sources of energy. The last independent variable captures the difference in authorized ROE between electric and natural gas utilities. The results of our regression analysis are presented in Table 1 below:

Table 1

	Coefficient	**t-stat**	**Adj. R^2**
Constant	7.634	38.717	0.371
U.S. Government 30-year Bond	0.428	15.864	
Moody's Utility A-rated Spread	0.310	6.344	
% Generation	0.008	7.335	
Natural Gas Dummy (Electric = 0; Gas = 1)	0.384	5.203	

The above results indicate that a one percent increase in generation will add nearly .8 basis points, the coefficient for "% Generation" to the authorized ROE. According to the historical linear relationship between authorized returns and percent of load generated (as opposed to purchased), an electric utility that generates one hundred percent of its distributed volume will have an ROE that is 80 basis points higher than a pure transmission and distribution utility. On average, our electric distribution proxy group has 49.76 percent generation as such, Concentric will reduce our electric proxy group ROE results by 40 basis points.

Our final comparator group consists of five publicly-traded Canadian utilities. The population of publicly-traded utilities in Canada is very limited so our group consists of utilities from all electric and natural gas utility sectors (i.e. generation, transmission and distribution). The five Canadian utilities are listed below:

1. Canadian Utilities Limited
2. Enbridge, Inc.
3. TransCanada Corporation
4. Emera Inc.
5. Fortis Inc.

Appendix D: Summary of the Risk Environment for Ontario's Utilities Relative to the Proxy Group Companies

A regulated utility faces three primary types of risk: 1) operating or business risk; 2) financial risk; and 3) regulatory risk. These terms are defined as follows:

1. Operating or business risk represents the variability in company earnings that might occur due to changes in demand, costs of raw materials and labor, operating leverage, management's ability to execute its business strategy, competition for market share, and obsolescence of plant and equipment.
2. Financial risk represents the possibility that a company will not have adequate cash flow to meet its business and financial obligations. For example, if a utility issues additional debt to finance capital projects or working capital, that additional leverage places greater demands and inflexible commitments on its cash flow, thereby increasing its financial risk.
3. Regulatory risk represents the threat that a change in laws or regulations will materially impact operating costs, reduce the attractiveness of investing in a particular business, or change the competitive landscape. Utilities are especially vulnerable to regulatory risks that can result from unexpected or adverse regulatory decisions concerning authorized returns, customer rates, service quality, and cost recovery.

In the following section, we examine the relative risk profiles of the Ontario and proxy group utilities on a variety of operating and financial performance metrics, as described below, to assess the relative risk profiles of the groups. In addition, we review the differences in regulatory risk between the proxy group utilities and Ontario utilities. For a review of the full risk analysis Concentric performed between the Ontario utilities and the respective proxy groups, please see Concentric - 04.

i. Operating Risks

Ontario is in the midst of an aggressive campaign to update its electric distribution grid and pursue green generation technologies that will result in enormous outlays of capital. First, Ontario's Integrated Power System Plan ("IPSP") estimates roughly $16 billion[55] (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

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

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.[56] 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.[57] 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. 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. To our knowledge, the magnitude of Ontario's green energy initiatives are unparalleled by any non-Canadian jurisdiction, and will require massive amounts of capital.

In addition to identifying this pressing need for capital, Concentric has comparatively examined the operating risk attributes between the proxy group companies and the Ontario utilities. That analysis is detailed in Exhibit Concentric-04 p. 5 of 8 and is summarized below. In the tables below, Concentric has compiled risk attributes for our North American gas and electric utility proxy groups and for the Ontario gas distribution and electric transmission and distribution companies. We have summarized a number of factors that are generally indicative of a utility's business risk: i) the credit rating of the utility (though primarily financial, does take into account certain operating characteristics that may affect the utility's ability to meet debt commitments); ii) regulated revenues (for a measure of scale); iii) number of distribution customers (to provide another measure of scale); iv) percent industrial revenue to total revenue (to assess the level of risk associated with potential large fluctuations in load due to fuel switching, bypass, or business closures); v) net property, plant, and equipment, as another measure of size of the company; vi) percent of FFO to CapEx, reflecting the company's ability to meet its current levels of capital expenditures; and vii) the competitive market environment the utility operates in. Additionally, we have noted the authorized return and equity ratio for each utility for reference.

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

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

Acknowledging data constraints, potential inconsistencies and other measures of operating risk not captured in these metrics, the tables below provide an overarching assessment of the comparability of the electric and natural gas proxy groups' business risk profiles compared to the Ontario utilities. We have gathered data, subject to accessibility, on each of the attributes mentioned above. The grey highlighted rows represent the holding companies, and the bolded italicized rows represent the regulated utility weighted averages for that particular company. The regulated utility metrics are averaged by weighting the utility's regulated revenue to total regulated revenue for the holding company. Each of the weighted averages for regulated operations by holding company is simply averaged for each holding company to obtain the proxy group average. We then compared the proxy group average to the Ontario utilities' average. Our findings are listed below:

Electric Utilities

- Credit ratings are comparable in the A range. The proxy group contains one AA- rated company whereby the Ontario utilities are all rated A or A+;
- Average ROE for the proxy group was 274 basis points higher than the Ontario utilities;
- Average common equity ratio for the proxy group had 9.83 percent more equity;
- The weighted average proxy group company revenue amount was 3.2x the size of the average Ontario electric utility;
- The weighted average proxy group number of distribution customers was 3.6x the number of Ontario distribution customers;
- The proxy group companies on average were significantly more dependent on industrial revenue at a weighted average representing 8.03 percent of total revenues versus the Ontario utilities at 4.30 percent;
- The net property, plant, and equipment for the proxy group was significantly larger than the Ontario utilities by a factor of 7.1x; and
- FFO/Capex in Ontario is 1.23 which is nearly identical to the electric proxy group weighted average of 1.21. (One factor that would lower this ratio is more rapid system growth or the need for system replacement. Utilities such as Duke and FPL would be expected to have lower ratios due to their growth. Conversely, utilities such as Con Ed would be expected to have major system reinvestment requirements.)

In summary, credit ratings between the two groups are comparable. The electric proxy group utilities are approximately three times larger than the Ontario electric utilities. Generally, smaller size exposes a utility to greater risks due to lack of diversity and liquidity; and larger size allows for greater economies and lower overall business risk. However, the Ontario electric utilities are not of such a small size as to be subject to significant size-related risk and we do not consider this size-related difference (between medium and large) to be a factor warranting an adjustment to the authorized return. Next, the proxy group electric utilities appear to be more dependent on their industrial base of customers than their Ontario counterparts. This implies greater exposure to load variability mentioned above. However, the proxy group companies' larger size may be of benefit in accommodating the larger industrial load. Lastly, both groups are equally situated with respect to their ability to fund current levels of capital expenditures. Overall, the business risk profiles of the two groups reveal offsetting risks, the large size of the proxy groups' electric utility's enable their ability to service a large percentage of industrial customers, and ultimately those risks offset. From a business risk perspective, the proxy group and Ontario utilities risks are comparable and no adjustment to the proxy group results is warranted for differences in risk.

Natural Gas Utilities

Similar to the comparison above for electric utilities, we have compared the proxy group gas utilities to the Ontario gas utilities. The results of that comparison are detailed in Table 2 and are summarized below:

- The U.S. and Ontario gas utilities are comparable in credit ratings;
- The Ontario gas utilities have comparable customer bases and revenues, though the Ontario utilities are slightly larger than the proxy group utilities;
- The Ontario net plant value is greater than that of the proxy group by a factor of 1.7x;
- FFO/Capex in Ontario is 1.71x which is slightly higher than the natural gas proxy group weighted average of 1.46x.

To summarize this review of operating risks, the Ontario gas utilities have comparable credit ratings; and the two groups are very similar in revenues and the average number of customers they serve. The Ontario gas utilities' net plant values are relatively higher than the proxy group's, which would indicate slightly lower risk. In addition, the Ontario utilities appear to be slightly better situated for meeting their capital expenditure levels with funds from operations, though not to a significant degree. Overall, based on this analysis, we view the Ontario gas distribution companies as having comparable to slightly lesser operating risks than the proxy group of gas distribution companies. However, these subtle differences in net plant and FFO/Capex ratio are not indicative of materially different risk profiles and do not warrant an adjustment to the results of the proxy group analysis or render the groups incomparable.

Based on our analysis, we conclude that the proxy group utilities and the Ontario utility companies have sufficiently comparable operating risk profiles to be considered appropriate proxies, and no adjustment is warranted to equate the two groups' results on the basis of operating risks.

Table 1: Business Risk Profile Ontario Utilities v. Electric Proxy Group

Ontario Electric LDCs	Ticker	Credit Rating	Auth. Return	Auth. Equity Ratio	Revenue	Customers	% Ind. Rev. / Total Rev.	Net Plant	FFO / CapEx	Restructured Market
Enersource Hydro Mississauga Inc.		A	8.57%	40.00%	670.7	185,324	N/A	419.2	N/A	Yes
Horizon Utilities Corporation		A+	8.57%	40.00%	98.1	234,000	2.60%	307.7	1.14	Yes
Hydro One Networks Inc. (Distribution)		A+	8.57%	40.00%	2,956.0	1,300,000	6.00%	4,336.0	0.92	Yes
Hydro Ottawa Limited		A	8.57%	40.00%	692.9	291,000	0.00%	494.7	0.91	Yes
PowerStream Inc.		N/A	8.01%	40.00%	606.2	314,044	N/A	445.7	1.39	Yes
Toronto Hydro Electric System		A	8.01%	40.00%	2,349.5	684,000	8.60%	1,786.9	1.65	Yes
Veridian Connections Inc.		A	9.00%	40.00%	228.8	110,861	N/A	134.4	1.39	Yes
AVERAGE ONTARIO ELECTRIC LDC			**8.47%**	**40.00%**	**1,086.0**	**445,604**	**4.30%**	**1,132.1**	**1.23**	
U.S. Electric LDCs										
CH Energy Group, Inc.	CHG	N/A	N/A	N/A	1,338.1	N/A	N/A	978.4	1.35	1/1
Central Hudson Gas & Electric Corp.		***A***	***10.00%***	***47.00%***	***798.0***	***288,262***	***3.03%***	***898.3***	***1.15***	***Yes***
Consolidated Edison, Inc.	ED	A-	N/A	N/A	13,941.0	3,560,781	N/A	20,874.0	1.26	4/4
Consolidated Edison Company of New York, Inc.		A-	10.00%	48.00%	10,573.1	3,261,503	6.39%	19,214.4	1.03	Yes
Orange & Rockland Utilities, Inc.		A-	9.40%	48.00%	777.6	222,343	7.28%	949.6	1.15	Yes
Pike County Light & Power Company		N/A	[1]	[1]	7.2	4,642	23.79%	11.9	0.61	Yes
Rockland Electric Company		A-	9.75%	46.51%	237.7	72,310	2.31%	183.1	1.20	Yes
Weighted Average based on Revenue			***9.95%***	***47.97%***	**--**	***2,990,301***	***6.37%***	***17,587.5***	***1.04***	**--**
DPL Inc.	DPL	A-	N/A	N/A	1,604.2	N/A	N/A	2,876.4	2.16	1/1
Dayton Power and Light Company		***A-***	***13.00%***	***49.57%***	***1,656.6***	***514,907***	***14.99%***	***2,700.3***	***2.16***	***Yes***
Duke Energy Corporation	DUK	A-	N/A	N/A	13,397.0	3,971,510	N/A	34,036.0	0.97	1/4
Duke Energy Carolinas, LLC		A-	11.63%	51.50%	5,881.8	2,364,469	17.73%	15,466.9	0.81	No
Duke Energy Indiana, Inc.		A-	10.50%	44.44%	2,480.7	776,674	24.00%	5,555.6	0.88	No
Duke Energy Kentucky, Inc.		A-	[2]	[2]	500.1	134,712	15.21%	862.6	1.70	No
Duke Energy Ohio, Inc.		A-	10.63%	51.59%	3,167.4	687,965	14.95%	6,632.0	1.64	Yes
Weighted Average based on Revenue			***11.11%***	***50.01%***	**--**	***1,502,943***	***18.19%***	***10,489.8***	***1.08***	**--**
FPL Group, Inc.	FPL	A	N/A	N/A	16,487.0	N/A	N/A	32,411.0	0.85	0/1
Florida Power & Light Company		***A***	***[2]***	***[2]***	***11,646.8***	***4,509,743***	***3.00%***	***16,286.7***	***0.99***	***No***
MGE Energy Group, Inc.		N/A	N/A	N/A	604.0	N/A	N/A	901.2	1.08	0/1
Madison Gas and Electric Company		***AA-***	***10.80%***	***57.36%***	***631.5***	***139,452***	***5.60%***	***781.7***	***0.96***	***No***
NSTAR	NST	A+	N/A	N/A	3,357.6	N/A	N/A	4,538.2	1.86	1/1
NSTAR Electric Company		***A+***	***[3]***	***[3]***	***2,902.4***	***1,143,367***	***5.00%***	***3,668.8***	***1.25***	***Yes***
Southern Company	SO	A	N/A	N/A	17,209.0	N/A	20.11%	35,878.5	1.09	0/4
Alabama Power Company		A	[4]	[4]	6,087.4	1,435,370	N/A	11,833.1	1.01	No
Georgia Power Company		A	[5]	[5]	8,546.4	2,346,768	N/A	15,873.6	1.12	No
Gulf Power Company		A	12.00%	41.02%	1,387.4	429,304	N/A	2,025.8	0.65	No
Mississippi Power Company		A	12.88%	53.68%	1,264.7	186,027	N/A	1,282.1	1.30	No
Weighted Average based on Revenue			***12.42%***	***47.06%***	**--**	***1,713,825***	**--**	***12,271.7***	***1.05***	**--**
AVERAGE ELECTRIC PROXY GROUP			**11.21%**	**49.83%**	**3,527.1**	**1,600,350**	**8.03%**	**8,085.6**	**1.21**	

Notes: [1] Pike County ROE & Equity Ratio Not Available; [2] ROE & Equity Ratio not revealed as part of settlement; [3] NSTAR: 50%/50% earnings sharing mechanism should its ROE exceed 12.5% or fall below 8.5%. [4] Alabama Power: Rates remain unchanged if ROE is projected to be between 13.0% and 14.5%, if actual ROE exceeds 14.5%, customer refunds are required, there is no provision for additional customer billings should the actual ROE fall below 13.0%. [5] Georgia Power: Rates evaluated against an ROE range of 10.25% to 12.25%. [6] We have not presented Hydro One Transmission in this analysis but its authorized ROE for 2009 is 8.01% with a 40.00% deemed equity ratio.

Table 2: Business Risk Profile Ontario Utilities v. Natural Gas Distribution Proxy Group

	Ticker	Credit Rating	Auth. Return	Auth. Equity Ratio	Revenue	Customers	Net Plant	FFO / CapEx
Ontario Gas LDCs								
Enbridge Inc.	ENB	A-	N/A	N/A	16,131.3	N/A	16,389.6	N/A
Enbridge Gas Distribution Inc.		***A-***	***8.39%***	***36.00%***	***3,011.0***	***1,900,000***	***3,660.7***	***1.62***
Spectra Energy Corporation	SE	BBB	N/A	N/A	5,074.0	N/A	13,639.0	N/A
Union Gas Limited		***BBB+***	***8.54%***	***36.00%***	***2,130.0***	***1,300,000***	***3,827.0***	***1.80***
AVERAGE ONTARIO GAS LDC			**8.47%**	**36.00%**	**2,570.5**	**1,600,000**	**3,743.9**	**1.71**
U.S. Gas LDCs								
AGL Resources Inc.	AGL	A-	N/A	N/A	2,806.0	N/A	3,816.0	1.59
Atlanta Gas Light Company		A-	10.90%	47.90%	606.1	1,557,000	2,077.8	1.77
Chattanooga Gas Company		N/A	10.20%	44.80%	124.5	62,000	108.8	1.43
Elizabethtown Gas		N/A	10.00%	53.00%	523.5	273,000	593.5	1.64
Elkton Gas		N/A	[1]	[1]	14.7	6,000	8.2	1.31
Florida City Gas		A-	11.25%	36.80%	93.3	104,000	145.1	N/A
Virginia Natural Gas, Inc.		A-	10.90%	52.40%	N/A	271,000	N/A	N/A
Weighted Average based on Revenue			***10.51%***	***48.83%***		***810,576***	***1,172.6***	***1.68***
Piedmont Natural Gas Company, Inc.	***PNY***	***A***	***11.55%***	***52.60%***	***2,118.1***	***949,605***	***2,241.7***	***1.60***
South Jersey Industries, Inc.	SJI	N/A	N/A	N/A	963.3	N/A	982.6	2.50
South Jersey Gas Company		***BBB+***	***10.00%***	***46.00%***	***568.0***	***340,136***	***876.6***	***1.96***
Sempra Energy	SRE	BBB+	N/A	N/A	11,456.0	N/A	16,865.0	1.16
Mobile Gas Service Corporation		N/A	13.60%	46.99%	108.5	93,000	124.9	1.77
San Diego Gas & Electric Co.		A	10.70%	49.00%	3,306.9	3,100,000	5,307.1	1.27
Southern California Gas Company		A	10.82%	48.00%	4,759.4	5,700,000	5,130.7	1.48
Weighted Average based on Revenue			***10.81%***	***48.39%***	***4,110.1***	***4,573,845***	***5,135.7***	***1.40***
Southwest Gas Corporation	***SWX***	***BBB***	***10.33%***	***43.48%***	***2,131.3***	***1,819,000***	***2,983.3***	***1.27***
Vectren Corporation	VVC	A-	N/A	N/A	2,524.2	N/A	3,110.5	1.28
Indiana Gas Company, Inc.		A-	10.20%	48.99%	865.0	568,000	759.2	N/A
Southern Indiana Gas and Electric Company, Inc.		A-	10.15%	47.05%	683.9	111,000	1,355.4	0.85
Vectren Energy Delivery of Ohio, Inc.		A-	[2]	[2]	408.1	317,000	459.1	N/A
Weighted Average based on Revenue			***10.18%***	***48.13%***	***706***	***355,949***	***905***	***0.85***
AVERAGE GAS PROXY GROUP			**10.56%**	**47.90%**	**1,926.8**	**1,474,852**	**2,219.1**	**1.46**

Notes: [1] Elkton Gas: ROE & Equity Ratio Not Available; [2] Vectren Energy Delivery of Ohio: ROE & Equity Ratio not revealed as part of settlement

ii. Financial Risks

The results of our financial comparison for Ontario and proxy group gas and electric utilities are as follows:

- Ontario's utilities have higher embedded debt costs than the proxy group companies, 60 bps higher for the electric utilities and 13 bps higher for the gas utilities;
- Ontario's utilities are significantly more leveraged than the proxy group companies, 8.71 percent more for the electric companies, noting that if the companies' actual equity ratios equaled their deemed equity ratios, this difference would be 14.65 percent more leverage in the Ontario electric utility capital structure than the proxy group. Similarly, the Ontario gas utilities are 13.82 percent more leveraged than the proxy group gas utilities;
- Ontario's utilities have lower interest coverage ratios for both the gas and electric companies by roughly 1x interest;
- Similarly, FFO interest coverage is much lower by a factor between 1 and 2, than the proxy group utilities for both electric and gas utilities; and
- FFO/Debt ratios are lower for Ontario utilities when compared to the respective gas and electric proxy group.

To summarize, the Ontario utilities are subject to a significantly higher level of financial risk than the proxy group utilities. Ontario's utilities have markedly less favorable financial metrics on every measure, due to their highly leveraged capital structures, which has a pronounced effect on coverage ratios and debt/capital ratios, resulting in ratios that are insufficient in some cases or on the cusp of being insufficient to justify an A bond rating. This financial leverage leaves less flexibility to weather economic downturns or unexpected regulatory events, such as disallowances or rate freezes. Further, financial leverage limits the ability of the utility to finance additional capital investments through debt, because lenders are not willing to grant unlimited access to debt capital. Therefore, the utility must rely on its ability to raise equity capital either from equity infusions from its parent organization or through external capital markets.

The significant difference in leverage between the proxy group utilities and the Ontario utilities is material and requires adjustment. The results of our proxy group analyses have been adjusted to provide a return for the Ontario utilities that is equivalent to the proxy group in terms of financial risk. This computation and leverage adjustment (using the Hamada formula) is discussed fully in Appendices E and F.

Table 3: Financial Risk Profile Ontario Utilities v. Electric Proxy Group

	Ticker	Revenue ($M)	Embedded Debt Cost	Actual Debt /Capital Ratio	EBIT Interest Coverage Ratio	FFO/ Interest Coverage	FFO/ Debt
Ontario Electric LDCs							
Enersource Hydro Mississauga Inc.		670.7	6.66%	56.25%	2.36	3.60	24.00%
Horizon Utilities Corporation		98.1	7.00%	39.80%	3.23	5.05	41.46%
Hydro One Networks Inc. (Distribution)		2,956.0	5.43%	58.41%	2.50	4.21	21.86%
Hydro Ottawa Limited		692.9	5.27%	55.77%	3.54	5.36	26.68%
PowerStream Inc.		606.2	5.67%	58.65%	2.58	4.08	21.02%
Toronto Hydro Electric System		2,349.5	6.01%	59.81%	2.05	4.11	25.71%
Veridian Connections Inc.		228.8	7.58%	49.72%	2.03	4.41	33.97%
AVERAGE ONTARIO ELECTRIC LDC		**1,086.0**	**6.23%**	**54.06%**	**2.61**	**4.40**	**27.81%**
U.S. Electric LDCs							
CH Energy Group, Inc.	CHG	1,338.1	4.90%	47.27%	3.25	4.36	24.14%
Central Hudson Gas & Electric Corp.		***798.0***	***4.90%***	***53.81%***	***1.88***	***3.64***	***20.16%***
Consolidated Edison, Inc.	ED	13,941.0	5.72%	51.01%	3.69	5.39	29.04%
Consolidated Edison Company of New York, Inc.		10,573.1	5.77%	50.05%	2.59	5.00	26.65%
Orange & Rockland Utilities, Inc.		777.6	N/A	46.68%	2.16	4.53	30.23%
Pike County Light & Power Company		7.2	N/A	42.29%	0.88	2.56	20.22%
Rockland Electric Company		237.7	N/A	0.00%	N/A	N/A	N/A
Weighted Average based on Revenue			***5.77%***	***48.79%***	***2.56***	***4.97***	***26.89%***
DPL Inc.	DPL	1,604.2	6.09%	61.40%	4.83	5.80	33.89%
Dayton Power and Light Company		***1,656.6***	***5.39%***	***37.44%***	***7.44***	***11.51***	***56.20%***
Duke Energy Corporation	DUK	13,397.0	5.95%	40.76%	3.63	5.74	29.48%
Duke Energy Carolinas, LLC		5,881.8	N/A	49.87%	2.90	6.28	28.59%
Duke Energy Indiana, Inc.		2,480.7	N/A	52.27%	2.68	5.84	23.89%
Duke Energy Kentucky, Inc.		500.1	N/A	45.48%	2.99	5.86	31.51%
Duke Energy Ohio, Inc.		3,167.4	N/A	21.43%	4.07	10.82	42.94%
Weighted Average based on Revenue			***--***	***42.69%***	***3.17***	***7.37***	***31.52%***
FPL Group, Inc.	FPL	16,487.0	5.83%	59.39%	3.59	5.49	26.11%
Florida Power & Light Company		***11,646.8***	***6.19%***	***42.59%***	***3.36***	***6.75***	***36.90%***
MGE Energy Group, Inc.		604.0	6.03%	45.36%	6.87	8.19	28.88%
Madison Gas and Electric Company		***631.5***	***6.03%***	***37.09%***	***3.33***	***5.96***	***31.61%***
NSTAR	NST	3,357.6	6.62%	62.85%	3.56	5.16	25.90%
NSTAR Electric Company		***2,902.4***	***5.49%***	***49.79%***	***3.49***	***5.12***	***22.58%***
Southern Company	SO	17,209.0	5.59%	56.80%	4.14	5.00	23.56%
Alabama Power Company		6,087.4	5.39%	51.49%	3.21	5.70	27.02%
Georgia Power Company		8,546.4	5.34%	51.46%	3.41	6.06	27.29%
Gulf Power Company		1,387.4	5.42%	52.02%	3.14	5.94	25.64%
Mississippi Power Company		1,264.7	5.51%	39.30%	5.75	11.29	46.84%
Weighted Average based on Revenue			***5.37%***	***50.63%***	***3.49***	***6.31***	***28.50%***
AVERAGE ELECTRIC PROXY GROUP			**5.59%**	**45.35%**	**3.59**	**6.45**	**31.79%**

Table 4: Financial Risk Profile Ontario Utilities v. Natural Gas Distribution Group

	Ticker	Revenue ($M)	Embedded Debt Cost	Actual Debt /Capital Ratio	EBIT Interest Coverage Ratio	FFO/ Interest Coverage	FFO/ Debt
Ontario Gas LDCs							
Enbridge Inc.	ENB	16,131.3	4.65%	66.64%	2.48	4.59	19.14%
Enbridge Gas Distribution Inc.		***3,011.0***	***6.60%***	***62.24%***	***2.19***	***3.32***	***20.90%***
Spectra Energy Corporation	SE	5,074.0	6.54%	61.71%	2.33	3.67	23.23%
Union Gas Limited		***2,130.0***	***6.24%***	***63.99%***	***2.47***	***3.47***	***20.12%***
AVERAGE ONTARIO GAS LDC		**2,570.5**	**6.42%**	**63.11%**	**2.33**	**3.40**	**20.51%**
U.S. Gas LDCs							
AGL Resources Inc.	AGL	2,806.0	5.33%	60.14%	4.21	5.16	23.34%
Atlanta Gas Light Company		606.1	6.72%	51.31%	2.44	4.76	29.93%
Chattanooga Gas Company		124.5	1.75%	49.15%	12.27	30.28	26.43%
Elizabethtown Gas		523.5	4.77%	46.40%	2.31	4.81	22.58%
Elkton Gas		14.7	7.14%	49.10%	1.60	2.39	19.67%
Florida City Gas		93.3	7.06%	49.27%	1.96	5.26	37.32%
Virginia Natural Gas, Inc.		N/A	N/A	N/A	N/A	N/A	N/A
Weighted Average based on Revenue			***5.54%***	***49.06%***	***3.25***	***7.12***	***27.18%***
Piedmont Natural Gas Company, Inc.	***PNY***	***2,118.1***	***6.72%***	***58.11%***	***4.16***	***4.89***	***23.54%***
South Jersey Industries, Inc.	SJI	963.3	7.17%	52.54%	6.03	6.03	27.15%
South Jersey Gas Company		***568.0***	***5.96%***	***50.47%***	***3.11***	***5.63***	***25.75%***
Sempra Energy	SRE	11,456.0	6.79%	48.34%	7.17	9.42	31.94%
Mobile Gas Service Corporation		108.5	8.99%	51.54%	3.07	6.43	36.63%
San Diego Gas & Electric Co.		3,306.9	5.93%	41.87%	3.51	7.32	46.19%
Southern California Gas Company		4,759.4	5.00%	47.72%	4.72	10.73	49.31%
Weighted Average based on Revenue			***5.43%***	***45.40%***	***4.21***	***9.29***	***47.88%***
Southwest Gas Corporation	***SWX***	***2,131.3***	***7.42%***	***56.51%***	***2.11***	***4.12***	***28.31%***
Vectren Corporation	VVC	2,524.2	6.41%	57.75%	3.12	5.11	27.06%
Indiana Gas Company, Inc.		865.0	6.44%	40.38%	2.25	4.86	27.62%
Southern Indiana Gas and Electric Company, Inc.		683.9	6.90%	52.46%	2.62	4.96	26.20%
Vectren Energy Delivery of Ohio, Inc.		408.1	N/A	0.00%	52.95	106.75	N/A
Weighted Average based on Revenue [1]			***6.64%***	***36.18%***	***2.41***	***4.90***	***26.99%***
AVERAGE GAS PROXY GROUP			**6.29%**	**49.29%**	**3.21**	**5.99**	**29.94%**

Notes: [1] Weighted average excludes EBIT/Interest and FFO/Interest for Vectren Energy Delivery of Ohio

iii. Regulatory Risks

In this section, Concentric will review and compare the differing regulatory policies and rate mechanisms that apply to the Ontario utilities to those of the proxy group companies to determine whether any adjustments are necessary to address significant regulatory differences. In our risk assessment, Concentric has categorized regulatory protection into the following categories:

Table 5: Regulatory Mechanisms

Major Risk Category	Importance	Specific Regulatory Risk Mitigation Mechanisms	Factors Considered in Developing Ranking
Volume Variability and Volumetric Protection	Primary	Weather Normalization, Revenue Decoupling, Straight Fixed Variable Rate Design, Tiered Rates, etc.	Exposure to declines in customer volume due to weather or, conservation. Applicability to all rate classes. Timeliness and ease of recovery.
Fuel and Purchased Power Costs	Primary	Purchased Gas Adjustment, Fuel Cost Pass Through, Timeliness of Recovery	Applicability to fuel costs, hedging, capacity, emissions costs. Timeliness and ease of recovery.
Regulatory Lag	Secondary	Forward Test Year, Forecasted Test Year, Adjusted Historic Test Year, Special Purpose Rate Proceedings, Other	Ability to incorporate projected data into revenue requirement and ability to keep revenue requirement current.
Financial Stability	Primary	Allowed ROE, Equity Ratio, Earnings Sharing Mechanisms, Ring Fencing	Level of return and equity ratio. Ability to enhance return through earnings sharing or incentive mechanisms.
Escalating Costs	Secondary	O&M Tracker, Inflation Adjustments	Inflation factors built into rates. Frequency of adjustment. Forward looking revenue requirement.
Major Capital Improvements	Primary	CWIP in Rate Base, Preapproval of Construction Costs, Cost Trackers	Applicability to capital projects. Magnitude of capital projects undertaken. Items included, i.e. pre-construction costs, AFUDC, accelerated depreciation, etc. Ease and timeliness of recovery.
Other Cost Recovery	Secondary	Cost Recovery of minor costs and expenses through deferral accounts, riders and cost trackers	Significance of cost recovery, i.e. DSM and environmental compliance were deemed very significant. Extent of deferral treatment. Timeliness and ease of recovery.

Our risk analysis reviewed the prevailing regulatory treatment for the Ontario gas and electric utilities in comparison to the members of the proxy groups. After a review of each company's regulatory mechanisms, we evaluated the expected effectiveness of the mechanism in mitigating the risk exposure for each category, and have provided a ranking between low and high (low being the least favorable). After developing a ranking for each individual utility company, in each category, we provided a weighting of those ranks to roll up to the holding company level. Those weighting were based on regulated revenue or on distribution customers, if revenue data was not available at the utility/jurisdiction level. Acknowledging that this is a qualitative and subjective exercise, we believe it provides an objective comparison that is representative of the regulatory risk environment, as well as the regulatory tools to mitigate such risks, for the Ontario utilities and the proxy group utilities.

<u>Electric Utilities</u>

Our findings for the regulatory risk analysis for electric utilities are summarized below:

- Fuel and purchased power recovery clauses offer similar protections to Ontario utilities and proxy companies – most pass through power costs directly to the consumer; some proxy companies have quarterly automatic pass through, while others require a regulatory proceeding. The need for a prudence review for reimbursement was considered negative, and use of spot prices by other Ontario utilities appears to have an element of price risk. Overall we have ranked Ontario and the proxy group recovery of fuel costs highly effective;
- Ontario utilities appear to have somewhat more revenue assurance against declining customer usage through their projected test year and annual forecasted volumes that build in estimates of conservation, with a true up occurring if conservation declines exceed initial estimates, essentially providing the same risk mitigation as a conservation decoupling mechanism;
- No Ontario utilities and very few proxy companies have revenue protection against variations in demand caused by abnormal weather;
- Ontario utilities use forecasted test year, but must wait up to one year for a rate decision; a majority of the proxy group companies also use either a fully-forecasted or a partially forecasted test year. Many jurisdictions require a portion of the test year to be forecasted when the decision is rendered;
- Ontario utilities are subject to an incentive regulation mechanism ("IRM") which adjusts rates upward annually by inflation less a productivity offset;
- Ontario utilities are allowed to increase rates through the IRM by claiming unanticipated capital expenditures above a specified threshold, and proxy companies are allowed to include CWIP in rate base which provides a cash return on assets that are not yet placed in service and generating revenue;

- Proxy group has higher authorized ROEs and higher equity ratios than Ontario utilities and more opportunities for increasing utility earnings;
- Proxy group has more earnings sharing mechanisms which reward utility for efficiency savings or superior reliability;
- Ontario utilities have more deferral accounts, but generally both have comparable deferral treatment for significant costs such as DSM or environmental compliance.

In summary for the electric utilities, in the areas of primary importance, we note that the Ontario utilities and the proxy group were equally protected for fuel cost recovery and large capital cost recovery. The Ontario utilities have slightly greater revenue stability (medium/high versus medium for the proxy group), but the proxy group has an enhanced opportunity to achieve returns (medium/high versus low for the Ontario utilities). Ontario utilities primarily benefit from the more timely recovery of costs through a forecast test year and timely recovery of significant capital improvements through a predetermined program of conservation riders and capital trackers. However, they do remain exposed to the risk of weather as well as the counterparty collection risk associated with passing through transmission and commodity costs to end-use customers. For those regulatory mechanisms that provide the most benefit, i.e. that address volume variability, fuel cost recovery or large capital expenditures, we find that there is not a significant difference between Ontario utilities and the proxy group. In fact, these subtle differences are essentially overshadowed by the lower level of financial support (i.e., lower deemed equity ratios) from a regulatory perspective. On this basis, it is appropriate to rate the regulatory risk protection afforded to Ontario's electric utilities as comparable to the proxy group electric utilities, but requiring adjustment for the increased debt leverage. The full regulatory risk analysis for the electric utilities can be found at Exhibit Concentric-04, page 1 of 8.

<u>Natural Gas Utilities</u>

Our findings of the risk analysis for natural gas utilities are summarized below:

- Ontario utilities pass purchased gas costs through to customers, as do proxy group utilities with the exception of Sempra subsidiaries which are subject to a tolerance band which requires sharing of commodity savings with customers above or below a certain level;
- Both Ontario utilities and the proxy group have reasonable protections against declining customer usage through decoupling mechanisms; several proxy group companies also have straight-fixed-variable (SFV) rate design to remove volumetric risk from rates;
- Most companies in the proxy group are not exposed to weather risk; neither Ontario gas utility has this revenue protection against abnormal weather;

- Ontario utilities operate under multi-year incentive regulation plans which allow annual increases in rates based on inflation less a productivity offset; the majority of the proxy group companies use a historical test year updated for known and measurable changes;
- US proxy group has higher authorized ROEs and higher equity ratios;
- One Ontario gas utility may include forecasted capital expenditures in rate base, two US utilities can place CWIP in rate base;
- Ontario utilities have more deferral accounts, but for significant initiatives such as main replacements, both groups are equally protected.

Overall, the gas proxy group utilities are comparable to the Ontario utilities in the primary areas, i.e. revenue stabilization or volumetric variability and fuel cost recovery. The primary benefit of the Ontario regulatory regime is the forecasted test year and the ability to true up volumetric differences between weather normalized actual and forecasted revenue. The Ontario gas utilities benefit by increasing their fixed charge with an annual adjustment, lessening their sensitivity to volumetric variability. Additionally, Ontario utilities have specified recovery programs for significant incremental capital investment, though such programs only address capital expenditures above specified levels deemed to be significant. Though there are subtle differences in regulatory risk in Ontario versus the proxy group's regulatory regimes, we consider such differences too subtle to merit an adjustment. The utilities are deemed to be comparable in terms of regulatory risk and protection, but require adjustment for additional debt leverage.

Table 1: Electric Utilities Regulatory Risk Assessment

Ontario Electric LDCs	Volume Variability and Volumetric Protection	Fuel Cost Volatility	Regulatory Lag	Financial Stability	Escalating Costs	Major Capital Improvements	Other Cost Recovery Mechanisms
Enersource Hydro Mississauga Inc.	medium/ high	medium/ high	medium/ high	low	medium/ high	high	medium/ high
Horizon Utilities Corporation	medium/ high	medium/ high	medium/ high	low	medium/ high	high	medium/ high
Hydro One Networks Inc. (Distribution)	medium/ high	medium/ high	medium/ high	low	medium/ high	high	high
Hydro Ottawa Limited	medium/ high	medium/ high	medium/ high	low	medium/ high	high	high
PowerStream Inc.	medium/ high	medium/ high	medium/ high	low	medium/ high	high	medium/ high
Toronto Hydro Electric System	medium/ high	medium/ high	medium/ high	low	medium/ high	high	medium/ high
Veridian Connections Inc.	medium/ high	medium/ high	medium/ high	low	medium/ high	high	medium/ high
AVERAGE ONTARIO ELECTRIC LDC	**medium/ high**	**medium/ high**	**medium/ high**	**low**	**medium/ high**	**high**	**medium/ high**
U.S. Electric LDCs							
CH Energy Group, Inc.	***medium/ high***	***high***	***high***	***medium/ high***	***medium/ high***	***medium***	***high***
Central Hudson Gas & Electric Corp.	medium/ high	high	high	medium/ high	medium/ high	medium	high
Consolidated Edison, Inc.	***medium/ high***	***high***	***high***	***medium/ high***	***medium/ high***	***medium***	***high***
Consolidated Edison Company of New York, Inc.	medium/ high	high	high	medium/ high	medium/ high	medium	high
Orange & Rockland Utilities, Inc.	high	high	high	medium/ high	medium/ high	medium	high
Pike County Light & Power Company		high	medium/ high		medium/ high		
Rockland Electric Company	low	high	medium	low/ medium	medium	medium/ high	medium/ high
DPL Inc.	***low***	***high***	***low***	***medium/ high***	***low/ medium***	***medium/ high***	***medium/ high***
Dayton Power and Light Company	low	high	low	medium/ high	low/ medium	medium/ high	medium/ high
Duke Energy Corporation	***low/ medium***	***medium/ high***	***low/ medium***	***medium***	***low/ medium***	***medium/ high***	***medium/ high***
Duke Energy Carolinas, LLC	low	medium/ high	low/ medium	medium	low	medium	medium/ high
Duke Energy Indiana, Inc.	low	medium	medium/ high	medium	high	medium/ high	high
Duke Energy Kentucky, Inc.	low	high	medium	medium	low	medium/ high	low/ medium
Duke Energy Ohio, Inc.	high	high	low	medium	low/ medium	medium/ high	high
FPL Group, Inc.	***medium***	***medium/ high***	***medium/ high***	***high***	***medium/ high***	***high***	***medium/ high***
Florida Power & Light Company	medium	medium/ high	medium/ high	high	medium/ high	high	medium/ high
MGE Energy Group, Inc.	***medium***	***medium/ high***	***medium/ high***	***medium/ high***	***medium/ high***	***medium/ high***	***medium***
Madison Gas and Electric Company	medium	medium/ high	medium/ high	medium/ high	medium/ high	medium/ high	medium
NSTAR	***high***	***high***	***medium***	***medium/ high***	***medium/ high***	***medium***	***medium***
NSTAR Electric Company	high	high	medium	medium/ high	medium/ high	medium	medium
Southern Company	***medium***	***medium/ high***	***medium/ high***	***high***	***medium/ high***	***medium/ high***	***medium***
Alabama Power Company	medium	medium/ high	medium/ high	high	medium/ high	medium/ high	medium
Georgia Power Company	medium	medium/ high	high	medium/ high	medium/ high	medium	low/ medium
Gulf Power Company	medium	medium/ high	medium/ high	high	medium/ high	high	medium/ high
Mississippi Power Company	medium	medium/ high	medium/ high	high	medium/ high	medium/ high	medium/ high
AVERAGE ELECTRIC PROXY GROUP	**medium**	**high**	**medium/ high**	**medium/ high**	**medium/ high**	**medium/ high**	**medium/ high**

Table2: Natural Gas Utilities Regulatory Risk Assessment

	Volume Variability and Volumetric Protection	Fuel Cost Volatility	Regulatory Lag	Financial Stability	Escalating Costs	Major Capital Improvements	Other Cost Recovery Mechanisms
Ontario Gas LDCs							
Enbridge Inc.							
Enbridge Gas Distribution Inc.	*medium/ high*	*high*	*high*	*medium*	*medium/ high*	*medium*	*high*
Spectra Energy Corporation							
Union Gas Limited	*medium/ high*	*high*	*high*	*medium*	*medium/ high*	*high*	*high*
AVERAGE ONTARIO GAS LDC	medium/ high	high	high	medium	medium/ high	medium/ high	high
U.S. Gas LDCs							
AGL Resources Inc.	*high*	*high*	*medium*	*medium/ high*	*medium*	*medium*	*medium/ high*
Atlanta Gas Light Company	high	high	medium/ high	medium/ high	medium	medium	high
Chattanooga Gas Company	medium/ high	high	low	medium/ high	low	high	low
Elizabethtown Gas	high	high	medium	medium/ high	high	medium/ high	high
Elkton Gas	high	high	low	low/ medium	low	low	low
Florida City Gas	low	high	medium	medium	medium	low	high
Virginia Natural Gas, Inc.	high	high	low	medium	medium	medium	low
Piedmont Natural Gas Company, Inc.	*medium/ high*	*high*	*low/ medium*	*medium*	*medium/ high*	*medium/ high*	*low*
South Jersey Industries, Inc.	*high*	*high*	*medium*	*medium/ high*	*high*	*medium/ high*	*low/ medium*
South Jersey Gas Company	high	high	medium	medium/ high	high	medium/ high	low/ medium
Sempra Energy	*high*	*medium/ high*	*high*	*medium/ high*	*medium/ high*	*low*	*medium*
Mobile Gas Service Corporation	medium/ high	medium/ high	medium/ high	high	medium/ high	low	low
San Diego Gas & Electric Co.	high	medium/ high	high	medium/ high	medium/ high	low	medium
Southern California Gas Company	high	medium/ high	high	medium/ high	medium/ high	low	low/ medium
Southwest Gas Corporation	*medium/ high*	*medium/ high*	*medium/ high*	*medium*	*low/ medium*	*low*	*low/ medium*
Vectren Corporation	*high*	*medium*	*medium/ high*	*medium*	*medium/ high*	*medium/ high*	*medium/ high*
Indiana Gas Company, Inc.	high	medium	medium/ high	medium	high	medium/ high	medium/ high
Southern Indiana Gas and Electric Company, Inc.	high	medium	medium/ high	medium	high	medium/ high	medium/ high
Vectren Energy Delivery of Ohio, Inc.	high	high	low/ medium	medium	low	medium/ high	medium/ high
AVERAGE GAS PROXY GROUP	high	medium/ high	medium/ high	medium/ high	medium/ high	medium	medium

To summarize the results of our risk analysis, we conclude with the following:

- Ontario utilities have much greater financial risk than do the North American proxy group companies,
- We have not identified any business profile characteristics that would, in themselves, render our proxy groups incomparable to the Ontario utilities. Generally, the gas and electric utility proxy groups share similar business profiles to the Ontario utilities.
- Ontario's utilities face enormous capital requirements to develop the necessary infrastructure to satisfy Ontario's green energy initiatives over the next several years. We are aware of no single jurisdiction, outside of the Canadian provinces, that share the same upcoming capital burden.
- Lastly, we have examined the regulatory protection afforded the proxy group utilities and the Ontario utilities through their rates. We have conducted a comparative analysis of risk-mitigating regulatory mechanisms, employed to: stabilize sales volumes, recover fuel costs, reduce regulatory lag, support financial stability, address cost increases, expedite cost recovery of large capital projects, and provide a means for recovering unexpected variations in expenses, to assist in indentifying the risks to which a utility remains exposed. Though we found the Ontario utility group to have differences in its regulatory mechanisms from the North American proxy groups, the differences were offsetting. The proxy group companies reveal a broader range of protection; but, on average, both groups share comparable regulatory support in mitigating risk. We have found no basis to conclude that an adjustment would be warranted to account for risk differences between the Ontario utilities and the proxy group, other than for the additional debt leverage in Ontario. Their risks are, on average, the same.

Our analysis reveals, that though there are differences between the mechanisms employed to address the many risks a regulated utility faces, the level of risk mitigation via rate mechanisms between the Ontario utilities and proxy group utilities are comparable, though the mechanisms themselves may be different. As the NEB has indicated in the excerpt above, if differences in the level of risk between the two groups were identified, it would be appropriate to account for them in the cost of capital analysis with an adjustment. We, however, have found no measureable differences between the proxy group averages and the Ontario utilities that would warrant such an adjustment. The supporting schedules to this risk analysis can be found at Exhibit Concentric-04. In addition, a full cost of capital analysis can be found in Appendix F.

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Appendix E: Adjusting ROE for Financial Leverage

The Hamada Equation decomposes the observed beta for a given company by removing the impact of leverage which results in a beta representing solely the business risk of the company. This would be the observed beta if there was no debt in the capital structure and all assets were financed solely with equity. In this scenario, the return on equity would be the same as the weighted average of the cost of capital.

$$\beta_{Unlevered} = \frac{\beta_{Levered}}{\left[1 + (1 - T_c)\frac{Debt}{Equity}\right]}$$

To incorporate the appropriate level of financial risk into the beta, beta is re-levered to reflect the debt percentage in the book capital structure (as applied in cost of service ratemaking), solving for the levered beta in the above formula. The formula is rearranged as follows:

$$\beta_{Levered} = \beta_{Unlevered}\left[1 + (1 - T_c)\frac{Debt}{Equity}\right]$$

As the capital structures for the Ontario utilities are significantly more levered than those of the U.S. proxy groups, the adjusted betas are higher when applied to a more levered capital structure.[58]

A leverage adjustment could also be performed by manipulating the after tax weighted average cost of capital formula ("ATWACC"). That equation is shown below:

$$ATWACC = ROE\ x\left(\frac{E}{C}\right) + B\ x(1 - Tc)x\left(\frac{D}{C}\right)$$

Where:

ROE = regulated return on equity
E = equity
D = debt
C = total long term capital (debt + equity)
B = debt cost
T_c = corporate tax rate

By manipulating the formula, one can solve for ROE for changes in leverage. However, this method assumes that ATWACC remains entirely flat as leverage changes. Rearranging the formula,

58 Financial textbooks generally instruct these calculations be performed on market value capital structures. In utility ratemaking, where returns are typically applied to book capital structures, we have used book values to de-lever and re-lever the beta.

one can solve for ROE at different levels of leverage by assuming that the after tax cost of capital is unaffected by the method by which assets are financed (debt or equity).[59]

$$ROE = \frac{ATWACC - [\, B\ x\ (1 - Tc)\ x\ \left(\frac{D}{C}\right)]}{\left(\frac{E}{C}\right)}$$

It should be noted that the NEB adopted an ATWACC recommendation for 2007 and 2008 for TQM, rather than conventional ROE and capital structure recommendations. The proposed ATWACC approach adopted by the NEB encompasses market weightings of debt and equity and imputes a market debt cost as opposed to using the utility's actual debt cost. Though we view the merits of this approach to be its natural accommodation to varying capital structures among utility applicants, and allows utilities to select their own capital structures, it's challenges are that it moves away from the regulatory cost based structure to a market based structure and employs assumptions to arrive at such a market based structure in the regulated environment. The approach adopted by the NEB also employs market based debt rates, which could prove problematic to the extent that a utility's embedded debt costs differed from market based debt costs, which they are highly likely to do.

[59] Modigliani and Miller ("MM") in their series of articles explained the modern financial theory with respect to cost of capital and capital structure. Those articles were: M. Miller and F. Modigliani, "Dividend Policy, Growth and the Valuation of Shares, " Journal of Business, October 1961; M. Miller and F. Modigliani, "The Cost of Capital, Corporation Finance, and the Theory of Investment," American Economic Review, June 1958; and F. Modigliani, "Debt, Dividend Policy, Taxes, Inflation and Market Valuation," Journal of Finance, May 1982. Modigliani-Miller Proposition 1, states that a firm cannot change the total value of its securities just by splitting its cash flows into different streams. The firms value is determined by its real assets, not by the securities it issues. Thus capital structure is irrelevant as long as the firm's investment decisions are taken as given. Imperfections not accounted for in the proposition include taxes, costs of bankruptcy, cost of writing and enforcing complicated debt contracts, imperfect markets, etc. Modigliani-Miller with taxes, recognizes that there is a tax benefit associated with the deductibility of interest expense that reverts to the shareholders. This will cause the ATWACC to decrease slightly as leverage increases.

Appendix F: Generic Cost of Capital Analysis for Ontario Regulated Utilities

In responding to the issues raised in the Board's issues list for this Consultative Process, Concentric has developed estimates of the cost of equity and recommended capital structure for Ontario's three utility sectors based on an analysis that incorporates electric distribution and transmission and gas distribution proxy groups, and the broader assessment of Canadian and U.S. utilities and their financial, regulatory, and operating environments. On balance, our recommendations are based on a synthesis of a considerable amount of financial, macroeconomic, and industry data, and broadly utilized methods for estimating capital costs. Concentric recommends the Board adopt the following sector-specific ROEs consistent with the corresponding equity ratios. This range is bordered by credit rating metrics on the lower threshold and comparable utility capital structures on the other.

Table 1

SUMMARY OF RECOMMENDED COMMON EQUITY RATIOS AND APPLICABLE ROES							
	COMMON EQUITY PERCENTAGE IN BOOK CAPITAL STRUCTURE						
	34%	36%	38%	40%	42%	44%	46%
Gas Distribution	11.3%	11.0%	10.7%	10.5%	10.2%	10.0%	9.8%
Electric Trans. and Dist.	11.2%	10.9%	10.6%	10.3%	10.1%	9.9%	9.7%

Next, we consider alternative approaches to updating the cost of equity over time. We have put forward four approaches that would all be superior to the current method in Ontario, and recommend an option based on a weighted index of Canadian utility bond yields and U.S. utility awards. Taken together, these recommendations would restore a fair cost of capital for Ontario's utilities and ensure the continued financial health of the Companies under reasonable market expectations. Concentric also believes the recommended process for updating the capital costs will provide regulatory flexibility and efficiency.

Role of Return on Capital in Setting Utility Rates

The foundations of public utility regulation call for the allowance of a fair rate of return that is sufficient to attract needed capital at reasonable rates, offer returns commensurate with investments of similar risk, and sufficient to maintain the financial integrity of the firm. This premise is commonly referred to as the "fair return standard". The rate of return on common equity compensates shareholders for the use of their capital to finance the plant and equipment necessary to provide regulated utility services. Investors are only willing to commit capital if they can reliably expect to earn a return commensurate with returns available for investments of comparable risk. Utilities generally do not charge market based rates for their services and thus their returns are set, as here, through Board administered rate proceedings. According to the guiding principles established through several landmark decisions, returns set through these proceedings must be sufficient to allow the utility to attract new capital on reasonable terms and to maintain financial integrity.

According to a regulatory history compiled by Major and Priddle[60], through the mid-1990s, Canadian utilities typically filed rate applications every one or two years, with ROEs set using one or more of four approaches: Comparable Earnings (CE), Discounted Cash Flow (DCF), Capital Asset Pricing Model (CAPM), or Equity Risk Premium (ERP). The adoption of a generic approach to ROE was ushered in by the following factors:

> 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 natural gas or electric ROE as a means of improving the efficiency or effectiveness of the regulatory process."[61]

In the wake of the precedent set by the BC Commission in 1994, other regulatory bodies in Canada followed suit; the NEB (1995), Manitoba (1995), Ontario (1997), Quebec (1999), and Alberta (2004) commissions adopted generic adjustment mechanisms in succession.[62] This approach was modified

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60 "The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results Implications", Hon. John C. Major, Former Justice, Supreme Court of Canada and Roland Priddle, Former Chair of the National Energy Board, March 2008.

61 Major and Priddle, op. cit., p.14, and citing the Ontario Energy Board Compendium to Draft Guidelines on a Formula-Based return on Common Equity for Regulated Utilities.

62 Major and Priddle, op. cit., pp.15-16.

by the NEB in March 2009 in its TQM Decision. The Board has embraced the NEB's definition of the fair return standard, as indicated in the preamble to questions 1, 2, and 3 of the issues list in this consultative process. In the following pages, the goal of our analysis is to determine the appropriate cost of capital and capital structure that will allow Ontario's utilities to attract needed capital and maintain financial integrity while offering investors returns comparable to those they can achieve elsewhere for investments of similar risk.

DCF Analysis

The DCF model evolves from the basic premise that investors will value a given investment according to the present value of its expected returns over time. This model has been used commonly in regulatory proceedings. It provides a view into the value of companies by discounting the projected cash flows for the enterprise. When valuing the entire enterprise, financial analysts discount the future stream of free cash flows. When considering the common stock of a company, investors consider the future stream of dividends as cash flow from this investment (characterized as the Dividend Discount Model). Efficient markets price a stock according to these expectations, leading to the expression:

$$P = \frac{D_0(1+g)^1}{(1+r)^1} + \frac{D_0(1+g)^2}{(1+r)^2} + \cdots + \frac{D_0(1+g)^\infty}{(1+r)^{n\infty}}$$

where:

P = the current stock price

g = the dividend growth rate

D_n = the dividend in year n

r = the cost of common equity.

Assuming a constant growth rate in dividends, the model may be rearranged to compute the ROE accordingly:

$r = \frac{D}{P} + g$

Stated otherwise, the cost of common equity is equal to the dividend yield plus the dividend growth rate. The basic model assumes that earnings and dividends grow at a constant rate and that the payout ratio remains constant. Extensions of this logic include varying growth rates, characterized by periods of differentiated growth, e.g., two-stage and multi-stage. Each period denotes a change in the growth rate, paralleling the maturation of the business. The dividend growth rate assumption represents long-term investor growth expectations. Earnings growth is a necessary condition for dividend growth and is considered to be a reasonable proxy for dividend growth by analysts in the DCF model.

In the 1997 Compendium, the Board noted that the benefit of the DCF method is that it "takes into consideration market and investor expectations and it relies upon published financial data including dividend rates and market prices".[63] One of the complicating issues, however, in the application of the DCF model is addressing how the dividends will actually grow over time. The Board noted this disadvantage in its Compendium, alluding to the difficulties in obtaining an unbiased growth rate estimate that reflects investors' forward looking expectations. "A general disadvantage of this model is that previous growth experience is not necessarily indicative of actual or expected future growth".[64]

Since the DCF Model is a forward looking model, the estimation of returns, should be based on forward-looking or projected growth data. Academic research has shown that analyst growth rates are accurate predictors of actual earnings growth. In addition, academic research has demonstrated the relationship between analysts' forecasts and investors' expectations.[65] Nonetheless, the DCF

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63 1997 Compendium to Draft Guidelines, at 5.

64 Ibid.

65 Brigham, Shome and Vinson noted that "…evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data, and (ii) investors do rely on analysts' forecasts." Also, Vander Weide and Carleton compare consensus financial analyst forecasts of earnings growth to 41 different historical growth measures (including sustainable growth/plowback growth). They concluded that there is "overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically-oriented growth measures in predicting the firm's stock price…consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions." In Dr. Roger A. Morin's book, New Regulatory Finance, Dr. Morin lists a multitude of empirical research that establishes the superiority of using analyst growth rates in estimating equity returns. In a study performed by Brown and Rozeff (1978), it was determined that Value Line growth estimates were superior to historical time series models in forecasting growth. In 1986, Harris concluded, when comparing analyst growth rates to historically derived growth rates, that analysts' earnings forecasts are indeed reflected in stock prices. In 1981, Elton, Gruber, and Gultekin established that stock prices react more to changes in analysts' forecasts of earnings than to changes in earnings themselves. In other studies, Keane and Runkle found: "Current financial disclosures, in addition to other financial information gathered

methodology is often called into question on the grounds of analyst bias in growth rate projections. Recent academic literature counters those claims and provides that analysts do not practice optimism bias; and, if anything, events over the last decade have led them to become overly conservative. The DCF analysis is attempting to measure investors' expectations for the future long-term growth of a given company. The best sources of investors' expectations are the consensus growth estimates reflecting the combined estimates of industry analysts covering a given public company. It has been demonstrated that consensus growth estimates significantly influence the expectations of individual investors.[66] Whether the growth rates are higher or lower than what is actually achieved is irrelevant to what we are measuring - investor expectations and the influence of those expectations on required returns.

As indicated previously, the Board was also troubled by the lack of market data for its regulated utilities. The Board concluded that it was "for those reasons that the DCF test was not generally relied on by experts or the Board in determining the ROE for the Ontario LDCs."[67]

Dividends

The current dividend yield for each company in the proxy group is calculated using the annualized current dividend[68] divided by the average stock price for the 90-trading days ended July 31, 2009. A 90-trading day average period represents a long enough period to eliminate short-term trading volatility and a short enough period to reflect recent value. Finally, the dividend yield for each proxy group company was increased by one-half of the assumed growth rate to reflect the expected growth in dividends over the coming year.

Growth Rates

We selected available earnings growth estimates from Value Line, Zacks, Thomson First Call and Bloomberg for each of the proxy companies. These four sources are widely recognized sources of

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by analysts, provide intelligent users of financial statements with enough information to predict the current condition of firms with reasonable accuracy." "Analysts do not systematically shade their forecasts; rather, their forecasts are unbiased." Timme and Eisemann concluded: "The results provide additional evidence that historical growth rates are poor proxies for investor expectations; hence, they should not be used to estimate utilities' cost of equity capital."

66 Ibid.

67 1997 OEB Compendium to the Draft Guidelines at 5.

68 Calculated as the current dividend multiplied by the number of dividend payments per year.

earnings forecasts. Not all of the earnings growth estimates were available for each company. Since Zacks, Thomson First Call, and Bloomberg are all consensus growth estimates, we averaged them together to arrive at one combined consensus forecast. To the extent there were missing growth estimates for any given company, we averaged those that we were able to obtain. As Value Line is an independent source of investment data and analysis, we then averaged the Value Line earnings growth estimate (as available) with the mean consensus growth estimate for each company to derive the earnings growth estimate we used in our DCF model. The growth rates utilized in our DCF model can be found in Exhibit Concentric-02.

DCF Results

For each proxy group company, the average growth rate was added to the expected dividend yield in order to calculate the DCF result. We have calculated the low DCF result, by taking the lowest of the available growth rates for a given company plus the expected dividend yield for that anticipated level of growth (i.e., multiplied the dividend yield by 1 plus one half of the *low* growth rate). Correspondingly, we have calculated the high DCF result in the same manner, using the highest of the four growth rates. Finally, we averaged the low, mean and high company-specific DCF results to obtain the unadjusted DCF results for the proxy group. To those results we have added a 50 basis point allowance for flotation costs and financing flexibility. This flotation cost allowance was acknowledged by the Board to be appropriate in its 2006 *Report of the Board*.[69]

The mean DCF results are shown below and are detailed in Exhibit Concentric-05.

Table 2: DCF Results Before Flotation Cost Adjustment

Proxy Group	**Low**	**Mean**	**High**
U.S. Natural Gas Distribution Utilities	9.70%	10.44%	11.57%
U.S. Electric Distribution Utilities	10.08%	10.96%	12.09%
Canadian Utilities	9.97%	10.60%	11.47%
Average	**9.92%**	**10.67%**	**11.71%**

69 Ontario Energy Board. *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors.* December 20, 2006. At p.17

Capital Asset Pricing Model Analysis

CAPM is an extension of the simple Equity Risk Premium model, where common equity investors are deemed to measure their required return based on a risk free rate of return plus compensation for the relative risk of a specific stock in relation to the broader market. This model may be expressed as:

$$R_e = R_f + \beta\ (R_m - R_f)$$

where:

R_e = the required return on common equity for a specific stock

R_f = the risk free rate of return

R_m = the return required for the market as a whole

β = Beta, a measure of the covariance between the returns (dividends plus capital gains) of the market average and those of a specific stock.

In order to calculate the CAPM, one must make assumptions about the risk-free rate of return, the market risk premium and beta. Since the CAPM is forward looking, it is appropriate to use forward-looking assumptions for the variables, if possible.

Risk Free Rate

In accordance with the convention established in the Ontario 1997 Draft Guidelines, we have developed forecasts of U.S. and Canadian 30-year bond yields by taking the average of the 3-month and 12-month forecasts of the respective 10-year government bond yields, as reported in the most recent Consensus Forecast issue dated July 13, 2009. To the forecast of the respective 10-year government bond yield, we have added the daily average historical spread between 10-year and 30-year bonds for July 2009. That convention resulted in the following 30-year bond yield forecasts for the U.S. and Canada in each country's native currency.

Table 3: Risk-Free Rate

30-Year Risk Free Yield	US$	CDN$
10-year bond yield forecast – 3-mos-out	3.70%	3.50%
10-year bond yield forecast – 12-mos-out	4.10%	3.80%
Average of 10-year forecasts	3.90%	3.65%
Average Daily Spread between 10-year and 30-year government bonds (July 2009)	0.87%	0.53%
Average	**4.77%**	**4.18%**

Beta

Beta measures the covariance of a proxy group company's stock returns relative to those of the aggregate market. It is typically calculated using a linear regression of the change in stock price vs. the change in a general market index, where beta represents the slope of the regression line. High betas (greater than 1.0) indicate greater covariance with the market, and therefore relatively greater risk. Conversely, low betas (lower than 1.0) indicate lower covariance to the market, and therefore relatively lower risk. The risk represents only that which cannot be diversified, or risks inherent in the market itself.

Concentric used two reputable sources for beta: Value Line and Bloomberg. When both sources of beta were available, they were averaged. According to Value Line, the reported historical beta for each company is based on 5 years of weekly stock returns and uses the New York Stock Exchange as the market index.[70] The results have been rounded to the nearest five hundredths and no information is reported regarding the statistical significance of the underlying regression. Bloomberg, on the other hand, produces beta estimates based on parameters entered by the user. The default parameters compute betas based on three years of weekly stock returns and use the S&P 500 or the TSX as the market index. Bloomberg results are rounded to the nearest thousandth and include additional information regarding the statistical significance of the underlying regression. Both Value Line and Bloomberg betas are adjusted to compensate for the tendency of beta to revert towards the market over time. In order to capture this effect, adjusted betas reported by both Value Line and Bloomberg have been used. [71]

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70 http://www.valueline.com/sup_glossb.html

71 Value Line adjusted beta = 0.371 + 0.635 * (raw beta). Source: Ibbotson Associates, *2006 Yearbook, Valuation Edition*, p. 116; Bloomberg adjusted beta = 0.33 + 0.67 * (raw beta). Source: Bloomberg output.

Though adjusted beta estimates are common place and are preferred by practitioners based on mounds of empirical evidence that has demonstrated the ability of adjusted beta to produce better estimates of equity costs, they are still subject to much debate in the regulatory community. There have been numerous empirical studies providing evidence that an individual company beta is more likely than not to move towards the market average of 1.00 over time.[72] In addition, adjusting beta serves a statistical purpose. Because betas are statistically estimated and have associated error terms, betas that are greater than 1.00 tend to have positive estimated errors and thus tend to overestimate future returns. Betas that are below the market average of 1.00 tend to have negative error terms and underestimate future returns. To adjust for this, it is necessary to adjust forecasted betas toward 1.00 in an effort to improve forecasts.[73] Because current stock prices reflect expected risk, one must use an expected beta (adjusted beta) to appropriately reflect investors' expectations. A raw beta reflects only where the stock price has been relative to the market historically and is an inferior proxy for the expected returns when compared to the adjusted beta.

Market Equity Risk Premium

Estimates of the market equity risk premium generally fall into two camps, ex-ante (or forward looking) and ex-post (historical arithmetic average). An ex-ante approach may infer the market risk premium from DCF-derived or ERP-derived ROE estimates, by subtracting the risk free rate and dividing by the respective proxy group beta. In regulatory proceedings, it is common to use a arithmetic average of historical risk premia over the longest period for which data is available. Morningstar Ibbotson calculates the risk premium for the U.S. as far back as 1926, and for Canada as far back as 1936. It is important to use the arithmetic mean, as compared to the geometric mean,

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72 There have been several studies to support the reversion of beta towards the market mean. In 1971, Blume examined all common stocks listed on the NYSE, and found a tendency for a regression of betas towards 1.00. He concluded that…there is obviously some tendency for the estimated values of the risk parameter to change gradually over time. This tendency is most pronounced in the lowest risk portfolios, for which the estimated risk in the second period is invariably higher than that estimated in the first period. There is some tendency for the high risk portfolios to have lower estimated risk coefficients in the second period than in those estimated in the first. Therefore, the estimated values of the risk coefficients in one period are biased assessments of the future values, and furthermore the values of the risk coefficients as measured by the estimates of βi tend to regress towards the means with this tendency stronger for the lower risk portfolios than the higher risk portfolios. In 1975, Blume revisited the topic, measuring the statistical significance of the regression tendency. He concluded, A comparison of the portfolio betas in the grouping period, even after adjusting for the order bias, to the corresponding betas in the immediately subsequent period discloses a definite regression tendency. This regression tendency is statistically significant at the five percent level for each of the last three grouping periods, 1940-47, 1947-54, 1954-61. Thus, this evidence strongly suggests that there is a substantial tendency for the underlying values of beta to regress towards the mean over time.

73 Roger A. Morin, *New Regulatory Finance*, at 74.

as the arithmetic mean treats each periodic return as an independent observation and, therefore, incorporates uncertainty into the calculation of the long-term average.[74] Because the U.S. and Canadian economies are integrated and capital flows freely across the border, arguably the independent risk premiums for each nation have merged to one North American equity risk premium. 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.[75]

Accordingly, it is appropriate in markets that are more similar than not, and where good reason does not exist to expect a continued divergence in market risk premiums (based on market indicators such as returns and interest rates), to derive a single forward looking estimate.

Concentric has selected 5.86 percent as our equity risk premium which is the midpoint of the long-horizon equity risk premia data averaged over the longest period for which data were available from Morningstar Ibbotson for both the U.S. and Canada. In the U.S., Ibbotson risk premia data is available from 1926-2008 and results in a 6.5 percent risk premium, the arithmetic mean of the premium of the S&P 500 returns over long-term government bond income returns for large company common stocks. In Canada, the longest period for which risk premia data is available

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[74] In his review of literature on the topic, Cooper noted the following rationale for using the arithmetic mean: Note that the arithmetic mean, not the geometric mean is the relevant value for this purpose. The quantity desired is the rate of return that investors expect over the next year for the random annual rate of return on the market. The arithmetic mean, or simple average, is the unbiased measure of the expected value of repeated observations of a random variable, not the geometric mean. …[the] geometric mean underestimates the expected annual rate of return. Ian Cooper, "Arithmetic versus geometric mean estimators: Setting discount rates for capital budgeting," *European Financial Management 2.2* (1996): 158.

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

from Ibbotson is from 1936 – 2008 in Canadian currency, which yielded an equity risk premium of 5.2 percent; and from 1939-2008 in U.S. dollars, yielding a 5.5 percent equity risk premium. The Canadian market is represented by the S&P/TSX Composite Index and earlier sources provided by Ibbotson Associates.[76] Concentric's equity risk premium estimate is an average of the U.S. and Canadian country-specific risk premia measured in their respective native currencies. We view the resulting equity risk premium as an appropriate North American indicator.

It is appropriate in markets that are more similar than not, and where good reason does not exist to expect a divergence in market risk premiums (based on market indicators such as returns and interest rates), to derive a single forward looking estimate.

The intuitive basis of the CAPM is that investors will seek to be compensated for the relative (or non-diversifiable) risk of a given stock in relation to a risk free investment and the broader market for equities. The Board noted that the data is generally available for investor-owned firms that are actively traded on the open market. However, in Ontario the fact that OEB-regulated utilities are not traded on the market means that CAPM estimates cannot be directly calculated for an Ontario utility, thus the Board was dissuaded from its use. Additionally the Board noted problems associated with quantifying the contentious and oft-disputed market equity risk premium, a vital input to the CAPM. Further, the Board noted the controversy surrounding beta risks, where academics and practitioners question its ability to capture the true risk characteristics of a firm and advise that there are other risks that may influence investors' decisions. The CAPM assumes that any risk that can be diversified in an investors' portfolio, is diversified. Though theoretically justified, this assumption may be out of line with actual investor behavior. Additionally, we have seen recognition that the government bond yield plus a risk premium does not adequately track the capital costs of a regulated utility.[77]

<u>CAPM Results</u>

Concentric's results are provided below and are described in detail in Exhibit Concentric-06.

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[76] Ibbotson Associates, *2008 Risk Premia Over Time Report,* Estimates from 1926-2007; Ibbotson - *Canadian Risk Premia over Time Report 2006;* and Morningstar International Equity Risk Premia Report 2008.

[77] NEB, Op. cit., at 17.

Table 4: CAPM Results Before Flotation Cost Adjustment

Proxy Group	Low	Mean	High
U.S. Natural Gas Distribution Utilities	9.05%	9.18%	9.32%
U.S. Electric Distribution Utilities	8.54%	8.68%	8.82%
Canadian Utilities	7.80%	7.95%	8.10%
Average	**8.46%**	**8.61%**	**8.75%**

Equity Risk Premium Analysis

The Equity Risk Premium is the preferred approach by the Board. It is described by the Board as relying on the assumption that "common equity is riskier than debt and that investors will demand a higher return on shares, relative to the return required on bonds, to compensate for that risk."[78] In its most basic form, the Equity Risk Premium method determines the cost of equity on the basis of an adjustment to a bond return available in the market. In theory, stocks should return a premium over bond yields, and that difference is the equity risk premium. Government bonds or corporate bonds are often used as a measure of the bond yield. The risk premium is typically derived from past performance of equity vs. bond returns. The formula is straightforward:

$$R = R_f + Rp$$

where:

R = the required return on common equity for a specific stock
R_f = the risk free rate of return or corporate bond yield

Rp = the risk premium.

The Board noted the benefits of the ERP method as being straight-forward and easy to understand; and with none of the data availability challenges present in the DCF and CAPM approach, as "bond yield data are widely available and publicly known".[79] However, even the ERP approach is not without its limitations. The Board noted that the risk premium itself can be a contentious issue, "since the proper estimation of the historical equity costs, on which it is based, is a matter of debate". The Board also noted that the "historical average risk premium calculations are time

[78] Draft Guidelines Compendium at 6.
[79] Ibid.

sensitive and subject to considerable volatility from period to period." Though these concerns are justified, the latter can be generally overcome by measuring the linear relationship between bond yields and equity returns, which helps to mitigate the problem of time sensitivity and volatility from period to period.

As discussed in the body of this Report, we performed a linear regression which equates to an equity risk premium analysis. The Formula that is used to set authorized returns today in Ontario is a form of the risk premium methodology and adjusts authorized returns based on 75 percent of the change in long-term Canadian government bond yields. Our model attempts to capture this relationship between historical authorized returns and government bond yields for U.S. electric and natural gas distribution utilities. We began with the population of electric and natural gas distribution rate case decisions between 1989 and 2009 as published by the Regulatory Research Associates. Each authorized return is paired to a corresponding U.S. government bond yield equal to the average of the 180 trading days prior to the decision date. In addition to government bond yields, we also considered the effect of the spread between the Moody's Utility A-rated Bond Index and the U.S. government 30-year bond. Similar to the average government bond yield, we calculated the average spread for the 180 trading days prior to the ROE's issuance date. For electric distribution utilities we also considered the percent of total load that is produced by an electric distribution utility's proprietary regulated generators. This data is sourced from the FERC Form 1, page 401a, and captures net generation in megawatt hours as a percent of total sources of energy for the year in which the ROE was issued. Our final consideration is the difference in authorized returns for electric and natural gas distribution utilities. The regression equation and its corresponding results are presented below:

Equation 1:

$$ROE = Constant + U.S.\ Gov.\ 30\text{-}year\ Bond \bullet x_1 + Moody\text{'}s\ Utility\ A\text{-}rated\ Spread \bullet x_2 + \%\ Generation \bullet x_3 + Natural\ Gas\ Dummy\ Variable \bullet x_4$$

Table 5: Regression Results

	Coefficient X_n	t-stat	Adj. R^2
Constant	7.634	38.717	0.371
U.S. Government 30-year Bond Yield	0.428	15.864	
Moody's Utility A-rated Spread	0.310	6.344	
% Generation	0.008	7.335	
Natural Gas Dummy (Electric = 0; Gas = 1)	0.384	5.203	

The results of this regression allow for the calculation of a hypothetical authorized ROE based on the four inputs. This concept is illustrated below using data for our electric and natural gas distribution proxy groups:

Table 6: Risk Premium Results

	U.S. Natural Gas Distribution Proxy Group	U.S. Electric Distribution Proxy Group
Constant	7.634	7.634
U.S. Government 30-year Bond Yield	0.428 x 4.18	0.428 x 4.18
Moody's Utility A-rated Spread (July 2009)	0.310 x 1.56	0.310 x 1.56
% Generation	0.008 x 0.00	0.008 x 49.76
Natural Gas Dummy (Electric = 0; Gas = 1)	0.384 x 1.00	0.384 x 0.00
Authorized ROE	**10.29%**	**10.30%**

The extrapolation of a Canadian authorized return on equity from historical U.S. data yields a 10.29 percent ROE for natural gas distribution utilities and a 10.30 percent ROE for electric distribution utilities. We are concerned that the relatively low R^2 suggests that other information is required to explain ROE. We therefore do not recommend what we believe is an overly-simplified approach with ERP.

We have developed estimates of generic cost of equity and recommended capital structures for Ontario's utilities based on the analysis we have conducted of the electric and gas proxy groups, and the broader assessment of Canadian and U.S. utilities and their operating environments. These findings are summarized below. On balance, our recommendations are based on a synthesis of a considerable amount of financial, macroeconomic, industry and corporate information. We have factored in the differences between Canadian and U.S. operating and financial environments through the careful selection of proxy groups, and utilization of Canadian specific data as appropriate. The ROEs are ultimately based on the two primary methodologies we have employed: DCF and CAPM, corroborated by a risk premium analysis. For context, we also report the low and high end of the range for each methodology and in total. The low estimates are based upon the lowest earnings growth rate estimates (DCF) and lowest beta estimates (CAPM) from the sources we have utilized, and conversely for the high estimates.

Our recommendations for both electric transmission only ("T"), and transmission and distribution (or "T&D") companies are derived from the same proxy group, consistent with FERC methods. Our approach is corroborated by the fact that U.S. transmission returns, authorized by the FERC, are based on proxy groups made up of vertically integrated electric utilities operating within the same region. Furthermore, we note that in Ontario the Board does not distinguish between electric distribution and electric transmission in terms of ROE, capital structure or risk.

> It is the Board's view that there really is no convincing quantitative evidence before us which suggests that transmission is more or less risky than distribution. It is true that distribution has greater and more immediate exposure to the possibility of bad debts. On the other hand, in absolute terms, the transmission system involves very large capital projects of significant complexity, which can be subject to delay in completion, and consequential delay in expected revenues. On balance, the Board concludes that the evidence before us does not provide a basis upon which we can make a finding that there is any meaningful difference in risk as between distribution and transmission.[80]

Below are our findings for electric distribution and transmission, assuming the proxy group benchmark for capital structure. We have based our recommendation for the generic ROE for Ontario's electric transmission and distribution on the mean result after the flotation adjustment of 9.93 percent ROE on a 46.32 percent equity share. We note that this result is lower than our risk premium analysis (see Table 6 of this Appendix) which produced a 10.30 percent ROE, prior to the flotation cost allowance, (10.80 after the flotation allowance) for the electric transmission and distribution group.

[80] EB-2006-0501 at 73.

Table 7: Electric T&D and Transmission-Only Benchmark ROEs

	Low	Mean/ Midpoint	High
U.S. Electric Transmission & Distribution Utilities			
DCF	10.08%	10.96%	12.09%
CAPM	8.54%	8.68%	8.82%
Average	**9.31%**	**9.82%**	**10.46%**
Differential between Vertically Integrated and T&D utilities	(0.40%)	(0.40%)	(0.40%)
Return before Adjustment for Leverage and Financing Flexibility	**8.91%**	**9.43%**	**10.06%**
Flotation/Financing Flexibility Adjustment	0.50%	0.50%	0.50%
Benchmark T&D ROE	**9.41%**	**9.93%**	**10.56%**
Benchmark T&D Equity Ratio	**46.32%**	**46.32%**	**46.32%**

We have reviewed the comparative risks of gas distribution utilities in Ontario versus those in our proxy group and have noted no significant differences. As such, we have found that the results of our proxy group returns adequately represent those for an Ontario gas distribution utility. We have based our recommendation for the generic ROE for Ontario's natural gas distribution utilities on the mean result of 10.65 percent ROE on a 40.32 percent equity share. We would similarly note that this result is corroborated by our risk premium analysis (see Table 6 of this Appendix) which produced a slightly higher 10.29% ROE, prior to the flotation cost allowance (10.79 after the flotation allowance), for the gas distribution group.

Table 8: Natural Gas Distribution Benchmark ROEs

	Low	Mean/ Midpoint	High
U.S. Natural Gas Distribution Utilities			
DCF	9.70%	10.44%	11.57%
CAPM	9.05%	9.18%	9.32%
Return before Adjustment for Leverage and Financing Flexibility	**9.37%**	**9.81%**	**10.45%**
Flotation/Financing Flexibility Adjustment	0.50%	0.50%	0.50%
Benchmark Natural Gas Distribution ROE	**9.87%**	**10.31%**	**10.95%**
Benchmark Natural Gas Distribution Capital Structure	**44.47%**	**44.47%**	**44.47%**

The Canadian proxy group result is well above ROEs currently awarded in Ontario. Due to the prevalence of the Formula impacting those results, we consider this an inferior proxy to our U.S. samples.

Table 9: Canadian Utility Company ROEs

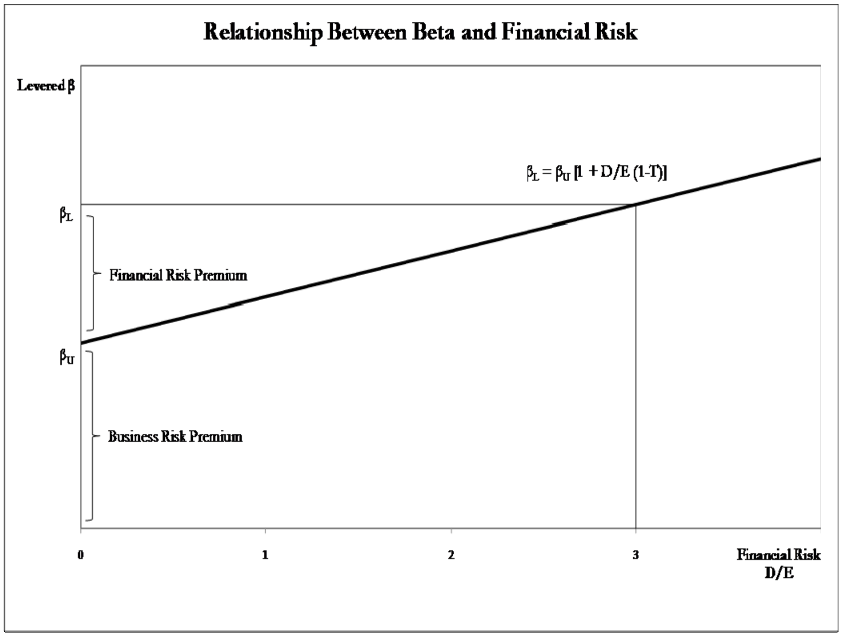
	Low	**Mean/ Midpoint**	**High**
Canadian Utility Company			
DCF	9.97%	10.60%	11.47%
CAPM	7.80%	7.95%	8.10%
Return before Adjustment for Leverage and Financing Flexibility	**8.89%**	**9.27%**	**9.79%**
Flotation/Financing Flexibility Adjustment	0.50%	0.50%	0.50%
Benchmark Canadian Utility Company ROE	**9.39%**	**9.77%**	**10.29%**
Benchmark Canadian Utility Company Equity Ratio	**37.67%**	**37.67%**	**37.67%**

<u>Leverage Adjustment</u>

Because the required return on equity increases as financial leverage increases, in situations where the debt ratios of the proxy companies are substantially different from those of the subject company, it is necessary to perform a calculation which de-levers and re-levers the beta of the proxy group to neutralize the risks that the capital structure imposes for any given company. This principle is shown graphically in Figure 1 and explained in greater detail in Appendix E. As described by Dr. Morin, the vertical axis represents the beta, or total risk, of the company. The horizontal axis denotes the degree of financial risk measured by the debt-equity ratio. For an all-equity financed company with no financial risk, the levered beta coincides with the unlevered beta. In other words, the company's total risk equals its business risk, as the financial risk is nil. As the financial risk increases, the total risk of the company increases steadily.[81]

[81] Dr. Roger A. Morin, *New Regulatory Finance*, at 222.

Figure 1



The formula below, known as the Hamada equation, decomposes the observed beta for a given company by removing the impact of leverage which results in a beta representing solely the business risk of the company. This would be the observed beta if there was no debt in the capital structure and all assets were financed solely with equity. In this scenario, the return on equity would be the same as the weighted average of the cost of capital.

$$\beta_{Unlevered} = \frac{\beta_{Levered}}{\left[1 + (1 - T_C)\frac{Debt}{Equity}\right]}$$

As the capital structure for the Ontario companies is significantly more levered than that of the U.S. proxy groups, the adjusted betas are higher when applied to a more levered capital structure.[82] To our adjusted re-levered CAPM results, we have added a 50 basis point adjustment for financing flexibility and flotation costs previously allowed by this Board. This computation and the associated schedules are shown in Exhibit Concentric-07.

82 Financial textbooks generally instruct these calculations be performed on market value capital structures. In utility ratemaking, where returns are typically applied to book capital structures, we have used book values to de-lever and re-lever the beta.

We have used the Hamada equation to adjust our DCF results for varying leverage percentages. To do this, we have inferred the market risk premium implied by our DCF results, by subtracting the risk free rate from the ROE estimated by our DCF analysis. We have then divided that result by the proxy group beta, effectively converting our DCF result to a CAPM result. We then performed the de-levering and re-levering as described above. To our re-levered results, we have added a 50 basis point adjustment for financing flexibility and flotation costs. Our calculations and the associated schedules are shown in detail in Exhibit Concentric-07.

We have observed in our data that the ATWACC continues to decline as leverage increases up to the point where the company is on the brink of a non-investment grade credit rating. Once a company has a non-investment grade credit rating, its debt costs rise sharply, and the ATWACC curve begins to slope upward. Therefore, the optimal financing structure is one that maximizes interest deductibility without risking a move into the non-investment grade credit ratings. So although the optimal capital structure may encourage maximizing leverage, there also must be adequate protection that the company will not be thrown into a non-investment grade scenario by some unforeseen event. It is important that a company have adequate financing flexibility to accommodate various unforeseen bumps in the road. We have estimated that financing flexibility and investment grade credit can be achieved with a 2.5x interest coverage ratio.

For each segment, Table 10 of this Appendix illustrates ROEs for a given debt-to-equity ratio. The range of debt ratios is bordered on one hand by the coverage ratio that optimizes leverage while satisfying prudent ratings criteria; on the other hand the range is bordered by the equity ratio average of the proxy group. The proxy group average represents the revealed capital structure associated with these representative industry comparables. Over this range, the average cost of capital for each segment is relatively flat. But, as more debt is added, ROE increases to compensate equity investors for the additional financial risk. Our leverage adjusted ROEs account for the difference between these equity ratios and those of the proxy groups.

Investment grade credit ratings and financial flexibility are necessary to operate and attract capital on reasonable terms in the utility sector. We would consider any of the ROE results produced from the proxy group analysis that would provide a benchmark 2.5x interest coverage ratio, to reflect the appropriate amount of leverage in the capital structure. Moving too far to the left of a 2.5x interest coverage ratio on the below Table represents debt levels that threaten the loss of financial flexibility and an investment grade credit rating; while moving too far to the right fails to optimize the use of less costly debt capital.

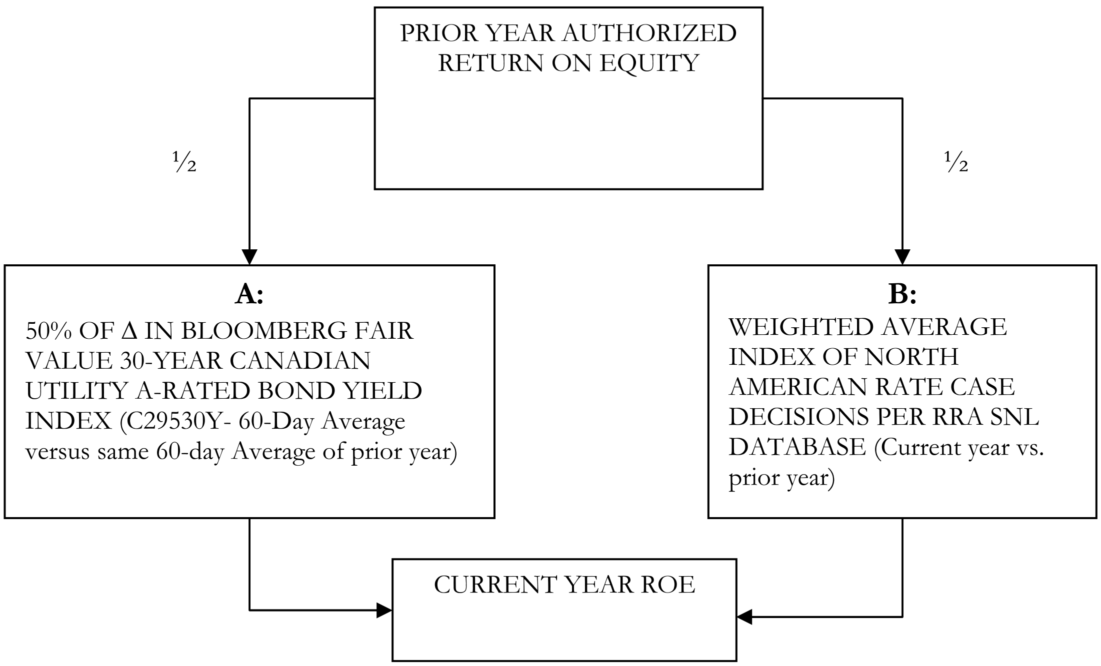
Table 10: Summary of Recommended Common Equity Ratios and Applicable ROEs

SUMMARY OF RECOMMENDED COMMON EQUITY RATIOS AND APPLICABLE ROES										
	COMMON EQUITY PERCENTAGE IN BOOK CAPITAL STRUCTURE									
	32%	34%	36%	38%	40%	42%	44%	46%	48%	50%
Gas Distribution	11.7%	11.3%	11.0%	10.7%	10.5%	10.2%	10.0%	9.8%	9.7%	9.5%
Coverage Ratio	2.3X	2.4X	2.4X	2.5X	2.6X	2.7X	2.8X	2.9X	3.1X	3.2X
Electric Transmission & Distribution	11.6%	11.2%	10.9%	10.6%	10.3%	10.1%	9.9%	9.7%	9.5%	9.3%
Coverage Ratio	2.3X	2.4X	2.5X	2.6X	2.7X	2.8X	2.9X	3.0X	3.1X	3.3X

We would recommend that the generic estimates be considered for differences in business or financial risk not already captured in the proxy groups, and use lower or higher debt ratios within the range specified to adjust for differences in risk profile, along with the corresponding ROEs. We would furthermore recommend that companies be given some flexibility to adopt a capital structure within these ranges to optimize their specific capital requirements.

Appendix G: Proposed Formula Adjustment Mechanism

INPUTS TO THE PROPOSED FORMULA:



PART A: BLOOMBERG 30-YEAR CANADA A-RATED UTILITY BOND INDEX:

The Bloomberg Fair Value Canada 30-Year A-rated Utility (C29530Y) curve is a yield curve based upon the below listed yields and maturities of Canadian dollar-denominated fixed-rate bonds, issued by Canadian utility companies, with ratings of A+, A, A- from S&P, Moody's, Fitch and/or DBRS. The index is not comprised solely of 30-year bonds, but rather is "derived" using an optimization model that solves simultaneously for all yields and maturity points in constructing the term structure of Canadian A-rated utility bond Issuances to best fit the existing bond yield data. The bond yields and maturities listed below serve as inputs to the optimization model and cannot be traced directly to the curve, *i.e.* the specific points on the curve are derived from the optimization model and do not correspond to any specific bond yield. The yields are from the secondary market (not new issues), thereby eliminating the ability of an issuing company to skew results. The same group of bonds is used to derive the Canadian Utility A-rated bond index for each maturity category. As each of the bonds rolls down the curve, new longer maturities are added.

Bloomberg Fair Value Curve - Canada Utility A-Rated			
Utility	**Issue Date**	**Maturity Date**	**Coupon Rate**
Canadian Utilities Ltd.	8/8/1990	8/15/2010	11.40%
Canadian Utilities Ltd.	11/28/1990	11/30/2020	11.77%
Canadian Utilities Ltd.	12/18/1991	4/1/2022	9.92%
Canadian Utilities Ltd.	12/8/1992	5/1/2023	9.40%
CU Inc.	5/16/2000	6/1/2011	7.05%
CU Inc.	11/1/2007	11/1/2012	4.88%
CU Inc.	1/23/2004	1/23/2019	5.43%
CU Inc.	11/20/2006	11/22/2021	4.80%
CU Inc.	3/6/2009	3/6/2024	6.22%
CU Inc.	5/26/2008	5/26/2028	5.56%
CU Inc.	11/18/2004	11/20/2034	5.90%
CU Inc.	11/21/2005	11/21/2035	5.18%
CU Inc.	11/20/2006	11/20/2036	5.03%
CU Inc.	11/1/2007	10/30/2037	5.56%
CU Inc.	3/6/2009	3/7/2039	6.50%
Enbridge Gas Distribution Inc.	12/3/1990	11/30/2010	11.95%
Enbridge Gas Distribution Inc.	4/23/1991	4/15/2011	10.80%
Enbridge Gas Distribution Inc.	11/12/2008	1/29/2014	5.57%
Enbridge Gas Distribution Inc.	9/24/2004	9/24/2014	5.16%
Enbridge Gas Distribution Inc.	12/3/2007	12/4/2017	5.16%
Enbridge Gas Distribution Inc.	12/19/2006	12/17/2021	4.77%
Enbridge Gas Distribution Inc.	7/3/1998	7/5/2023	6.05%
Enbridge Gas Distribution Inc.	11/22/1994	12/2/2024	9.85%
Enbridge Gas Distribution Inc.	10/2/1995	10/2/2025	8.85%
Enbridge Gas Distribution Inc.	10/29/1996	10/29/2026	7.60%
Enbridge Gas Distribution Inc.	11/3/1997	11/3/2027	6.65%
Enbridge Gas Distribution Inc.	11/15/2002	11/15/2032	6.90%
Enbridge Gas Distribution Inc.	12/16/2003	12/16/2033	6.16%
Enbridge Gas Distribution Inc.	2/24/2006	2/25/2036	5.21%
FortisAlberta Inc.	10/25/2004	10/31/2034	6.22%
Gaz Metro Inc.	11/2/1999	11/2/2009	6.95%
Gaz Metro Inc.	10/14/2008	4/15/2013	5.40%
Gaz Metro Inc.	7/10/2006	7/12/2021	5.45%
Gaz Metro Inc.	5/16/1995	5/16/2025	9.00%

Bloomberg Fair Value Curve - Canada Utility A-Rated			
Utility	**Issue Date**	**Maturity Date**	**Coupon Rate**
Gaz Metro Inc.	7/10/2006	7/10/2036	5.70%
Gaz Metro L.P.	10/25/1991	10/31/2016	10.45%
Gaz Metro L.P.	10/26/2000	10/30/2030	7.05%
Gaz Metro L.P.	10/31/2003	10/31/2033	6.30%
Hydro One Inc.	6/1/2000	6/3/2010	7.15%
Hydro One Inc.	11/19/2008	11/19/2010	3.89%
Hydro One Inc.	6/22/2001	12/1/2011	6.40%
Hydro One Inc.	9/17/2002	11/15/2012	5.77%
Hydro One Inc.	11/10/2008	11/12/2013	5.00%
Hydro One Inc.	3/3/2006	3/3/2016	4.64%
Hydro One Inc.	10/18/2007	10/18/2017	5.18%
Hydro One Inc.	6/1/2000	6/3/2030	7.35%
Hydro One Inc.	6/22/2001	6/1/2032	6.93%
Hydro One Inc.	1/31/2003	1/31/2034	6.35%
Hydro One Inc.	5/19/2005	5/20/2036	5.36%
Hydro One Inc.	3/13/2007	3/13/2037	4.89%
Hydro One Inc.	3/3/2009	3/3/2039	6.03%
Hydro One Inc.	4/22/2003	4/22/2043	6.59%
Hydro Ottawa Holdings Inc.	2/9/2005	2/9/2015	4.93%
Newfoundland Power Inc.	8/9/1989	8/1/2014	10.55%
Newfoundland Power Inc.	5/2/1991	5/2/2016	10.90%
Newfoundland Power Inc.	6/15/1992	6/15/2022	10.13%
Newfoundland Power Inc.	10/31/2002	11/1/2032	7.52%
Terasen Gas Inc.	12/3/1990	9/30/2015	11.80%
Terasen Gas Inc.	11/21/1991	9/30/2016	10.30%
Terasen Gas Inc.	9/21/1999	9/21/2029	6.95%
Terasen Gas Inc.	4/29/2004	5/1/2034	6.50%
Terasen Gas Inc.	2/25/2005	2/26/2035	5.90%
Terasen Gas Inc.	9/25/2006	9/25/2036	5.55%
Terasen Gas Inc.	10/2/2007	10/2/2037	6.00%
Terasen Gas Inc.	5/13/2008	5/13/2038	5.80%
Terasen Gas Inc.	2/24/2009	2/24/2039	6.55%
Terasen Gas Vancouver Island Inc.	2/15/2008	2/15/2038	6.05%

PART B: NORTH AMERICAN RATE CASE STATISTICS

The companies included in the SNL RRA database for 2008 are listed below:

Electric Rate Case Statistics Details

State	Company	Case Identification
Arizona	Tucson Electric Power Co.	D-E-01993A-07-0402
Arizona	UNS Electric Inc.	D-E-04204A-06-0783
California	San Diego Gas & Electric Co.	Ap-06-12-009 (elec.)
Connecticut	Connecticut Light & Power Co.	D-07-07-01
District of Columbia	Potomac Electric Power Co.	FC-1053
Hawaii	Hawaiian Electric Co.	D-04-0113
Idaho	Avista Corp.	C-AVU-E-08-01
Illinois	Central Illinois Light Co.	D-07-0585
Illinois	Central Illinois Public	D-07-0586
Illinois	Commonwealth Edison Co.	D-07-0566
Illinois	Illinois Power Co.	D-07-0587
Massachusetts	Fitchburg Gas & Electric Light	DPU-07-71
Michigan	Consumers Energy Co.	C-U-15245
Michigan	Detroit Edison Co.	C-U-15244
Minnesota	Otter Tail Corp.	D-E-017/GR-07-1178
Missouri	Empire District Electric Co.	C-ER-2008-0093
Montana	MDU Resources Group Inc.	D-D2007.7.79
North Dakota	Northern States Power Co. - MN	C-PU-07-776
New Mexico	Public Service Co. of NM	C-07-00077-UT
New Mexico	Southwestern Public Service Co	C-07-00319-UT
Nevada	Sierra Pacific Power Co.	D-07-12001
New York	Consolidated Edison Co. of NY	C-07-E-0523
New York	Orange & Rockland Utlts Inc.	C-07-E-0949
Oregon	Portland General Electric Co.	D-UE-197
Utah	PacifiCorp	D-07-035-93
Virginia	Appalachian Power Co.	C-PUE-2008-00046
Vermont	Central Vermont Public Service	D-7321
Washington	Avista Corp.	D-UE-08-0416
Washington	Puget Sound Energy Inc.	D-UE-07-2300
Wisconsin	Northern States Power Co - WI	D-4220-UR-115 (elec)
Wisconsin	Wisconsin Electric Power Co.	D-5-UR-103 (WEP-EL)
West Virginia	Appalachian Power Co.	C-08-0278-E-P
Wyoming	PacifiCorp	D-20000-277-ER-7

Natural Gas Rate Case Statistics Details

State	Company	Case Identification
Arizona	Southwest Gas Corp.	D-G-01551A-07-0504
California	San Diego Gas & Electric Co.	AP-06-12-009 (gas)
California	Southern California Gas Co.	AP-06-12-010
California	Southwest Gas Corp.	A-07-12-022 (SoCalDiv)
California	Southwest Gas Corp.	A-07-12-022 (NoCalDiv)
California	Southwest Gas Corp.	A-07-12-022 (LkTah)
Colorado	SourceGas Distribution LLC	D-08S-108G
Delaware	Chesapeake Utilities Corp.	D-07-186
Georgia	Atmos Energy Corp.	D-27163-U
Idaho	Avista Corp.	C-AVU-G-08-01
Illinois	Central Illinois Light Co.	D-07-0588
Illinois	Central Illinois Public	D-07-0589
Illinois	Illinois Power Co.	D-07-0590
Illinois	North Shore Gas Co.	D-07-0241
Illinois	Peoples Gas Light & Coke Co.	D-07-0242
Indiana	Indiana Gas Co.	Ca-43298
North Carolina	Piedmont Natural Gas Co.	D-G-9, Sub 550
North Carolina	Public Service Co. of NC	D-G-5, Sub 495
New Jersey	New Jersey Natural Gas Co.	D-GR-07110889
Ohio	Columbia Gas of Ohio Inc	C-08-0072-GA-AIR
Ohio	Duke Energy Ohio Inc.	C-07-0589-GA-AIR
Oregon	Avista Corp.	D-UG-181
Rhode Island	Narragansett Electric Co.	D-3943
Texas	Atmos Energy Corp.	GUD-9762
Texas	CenterPoint Energy Resources	GUD 9791
Utah	Questar Gas Co.	D-07-057-13
Washington	Avista Corp.	D-UG-08-0417
Washington	Northwest Natural Gas Co.	D-UG-08-0546
Washington	Puget Sound Energy Inc.	D-UG-07-2301
Wisconsin	Northern States Power Co - WI	D-4220-UR-115 (gas)
Wisconsin	Wisconsin Electric Power Co.	D-5-UR-103 (WEP-GAS)
Wisconsin	Wisconsin Gas LLC	D-5-UR-103 (WG)

U.S. GAS DISTRIBUTION UTILITIES SCREENING CRITERIA

		[1]	[2]	[3]	[4]	[5]
	Ticker	Pays Dividends	Credit Rating ≥ BBB & ≤ A+	Regulated Revenue ≥ 60% Total Revenue	Gas Dist. Revenue ≥ 60% Total Regulated Revenue	Not Party to Merger / Acquisition
AGL Resources Inc.	**AGL**	✓	✓	✓	✓	✓
Atmos Energy Corp.	ATO	✓	✓		✓	✓
Laclede Group, Inc. (The)	LG	✓	✓		✓	✓
New Jersey Resources Corporation	NJR	✓	✓		✓	✓
Nicor Inc.	GAS	✓		✓	✓	✓
NiSource Inc.	NI	✓		✓	✓	✓
Northwest Natural Gas Company	NWN	✓		✓	✓	✓
Piedmont Natural Gas Company, Inc.	**PNY**	✓	✓	✓	✓	✓
Sempra Energy	**SRE**	✓	✓	✓	✓	✓
South Jersey Industries, Inc.	**SJI**	✓	✓	✓	✓	✓
Southwest Gas Corporation	**SWX**	✓	✓	✓	✓	✓
UGI Corporation	UGI	✓	✓		✓	✓
Vectren Corporation	**VVC**	✓	✓	✓	✓	✓
WGL Holdings, Inc.	WGL	✓			✓	✓

Sources:
[1] Bloomberg
[2] Bloomberg
[3] 2006-2008 Annual 10-K Reports
[4] 2006-2008 Annual 10-K Reports
[5] SNL Financial

U.S. ELECTRIC DISTRIBUTION UTILITIES SCREENING CRITERIA

		[1]	[2]	[3]	[4]	[5]
	Ticker	Pays Dividends	Credit Rating ≥ A-	Regulated Revenue ≥ 60% Total Revenue	Electric Revenue ≥ 60% Total Regulated Revenue	Not Party to Merger / Acquisition
Allegheny Energy, Inc.	AYE	✓		✓	✓	✓
ALLETE, Inc.	ALE	✓		✓	✓	✓
Alliant Energy Corporation	LNT	✓		✓	✓	✓
Ameren Corporation	AEE	✓		✓	✓	✓
American Electric Power Company, Inc.	AEP	✓		✓	✓	✓
Avista Corporation	AVA	✓		✓		✓
Black Hills Corporation	BKH	✓		✓	✓	✓
CenterPoint Energy, Inc.	CNP	✓		✓		✓
Central Vermont Public Service Corp.	CV	✓		✓	✓	✓
CH Energy Group, Inc.	**CHG**	✓	✓	✓	✓	✓
Cleco Corporation	CNL	✓		✓	✓	✓
CMS Energy Corporation	CMS	✓		✓		✓
Consolidated Edison, Inc.	**ED**	✓	✓	✓	✓	✓
Constellation Energy Group, Inc.	CEG	✓			✓	✓
Dominion Resources, Inc.	D	✓	✓			✓
DPL Inc.	**DPL**	✓	✓	✓	✓	✓
DTE Energy Company	DTE	✓		✓	✓	✓
Duke Energy Corporation	**DUK**	✓	✓	✓	✓	✓
Edison International	EIX	✓		✓	✓	✓
El Paso Electric Company	EE			✓	✓	✓
Empire District Electric Company	EDE	✓		✓	✓	✓
Entergy Corporation	ETR	✓		✓	✓	✓
Exelon Corporation	EXC	✓		✓	✓	✓
FirstEnergy Corp.	FE	✓		✓	✓	✓
FPL Group, Inc.	**FPL**	✓	✓	✓	✓	✓
Great Plains Energy Inc.	GXP	✓		✓	✓	✓
Hawaiian Electric Industries, Inc.	HE	✓		✓	✓	✓
IDACORP, Inc.	IDA	✓		✓	✓	✓
Integrys Energy Group, Inc.	TEG	✓				✓
ITC Holdings Corp.	ITC	✓		✓	✓	✓
MGE Energy, Inc.	**MGEE**	✓	✓	✓	✓	✓
Northeast Utilities	NU	✓		✓	✓	✓
NSTAR	**NST**	✓	✓	✓	✓	✓
NV Energy, Inc.	NVE	✓		✓	✓	✓
OGE Energy Corp.	OGE	✓		✓	✓	✓
Otter Tail Corporation	OTTR	✓			✓	✓
Pepco Holdings, Inc.	POM	✓			✓	✓
PG&E Corporation	PCG	✓		✓	✓	✓
Pinnacle West Capital Corporation	PNW	✓		✓	✓	✓
PNM Resources, Inc.	PNM	✓		✓	✓	✓
Portland General Electric Company	POR	✓		✓	✓	✓
PPL Corporation	PPL	✓			✓	✓
Progress Energy, Inc.	PGN	✓		✓	✓	✓
Public Service Enterprise Group Inc.	PEG	✓		✓		✓
SCANA Corporation	SCG	✓		✓	✓	✓
Sempra Energy	SRE	✓		✓		✓
Southern Company	**SO**	✓	✓	✓	✓	✓
TECO Energy, Inc.	TE	✓		✓	✓	✓
UIL Holdings Corporation	UIL	✓		✓	✓	✓
UniSource Energy Corporation	UNS	✓		✓	✓	✓
Vectren Corporation	VVC	✓	✓	✓		✓
Westar Energy, Inc.	WR	✓		✓	✓	✓
Wisconsin Energy Corporation	WEC	✓		✓		✓
Xcel Energy Inc.	XEL	✓		✓	✓	✓

Sources:
[1] Bloomberg
[2] Bloomberg
[3] 2006-2008 Annual 10-K Reports
[4] 2006-2008 Annual 10-K Reports
[5] SNL Financial

U.S. NATURAL GAS DISTRIBUTION UTILITIES FORECAST AND FINANCIAL DATA

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
	Ticker	Credit Rating	Bloomberg Beta	Value Line Beta	Bloomberg Earnings Growth	Value Line Earnings Growth	Thomson First Call Earnings Growth	Zacks Earnings Growth	Regulated Revenue / Total Revenue	Regulated Operating Income / Total Operating Income	Regulated Gas Revenue / Total Regulated Revenue	Regulated Gas Operating Income / Total Regulated Operating Income
AGL Resources Inc.	AGL	A-	0.78	0.75	4.25%	3.50%	4.25%	5.30%	63.95%	66.54%	100.00%	100.00%
Piedmont Natural Gas Company, Inc.	PNY	A	0.70	0.65	5.76%	6.00%	6.20%	6.60%	100.00%	100.25%	100.00%	100.00%
Sempra Energy	SRE	BBB+	0.85	0.90	6.36%	5.00%	6.61%	6.50%	68.47%	45.13%	65.69%	80.05%
South Jersey Industries, Inc.	SJI	BBB+	0.66	0.65	8.33%	5.50%	9.67%	9.50%	64.66%	58.49%	100.00%	100.00%
Southwest Gas Corporation	SWX	BBB	0.88	0.75	5.00%	5.00%	6.00%	6.00%	84.39%	91.31%	100.00%	100.00%
Vectren Corporation	VVC	A-	0.73	0.75	6.33%	5.50%	6.43%	7.10%	78.94%	74.30%	73.31%	48.47%

Sources:
[1] Bloomberg
[2] Bloomberg
[3] Value Line
[4] Bloomberg
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] 2006-2008 Annual 10-K Reports
[9] 2006-2008 Annual 10-K Reports
[10] 2006-2008 Annual 10-K Reports
[11] 2006-2008 Annual 10-K Reports

U.S. ELECTRIC DISTRIBUTION UTILITIES FORECAST AND FINANCIAL DATA

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
	Ticker	Credit Rating	Bloomberg Beta	Value Line Beta	Bloomberg Earnings Growth	Value Line Earnings Growth	Thomson First Call Earnings Growth	Zacks Earnings Growth	Regulated Revenue / Total Revenue	Regulated Operating Income / Total Operating Income	Regulated Electric Revenue / Total Regulated Revenue	Regulated Electric Operating Income / Total Regulated Operating Income	Net Generation (MWh) / Total Energy Sources (MWh)
CH Energy Group, Inc.	CHG	A	0.73	0.65	--	3.00%	--	0.00%	63.89%	89.29%	77.15%	78.10%	2.05%
Consolidated Edison, Inc.	ED	A-	0.65	0.65	4.48%	2.50%	3.00%	4.30%	83.67%	96.34%	75.31%	75.84%	2.67%
DPL Inc.	DPL	A-	0.65	0.60	10.00%	8.00%	9.33%	7.40%	79.05%	114.95%	100.00%	100.00%	85.42%
Duke Energy Corporation	DUK	A-	0.74	0.65	4.09%	5.00%	3.67%	4.80%	76.61%	90.19%	88.89%	88.89%	82.56%
FPL Group, Inc.	FPL	A	0.83	0.75	9.19%	10.00%	9.59%	9.00%	74.48%	58.16%	100.00%	100.00%	84.18%
MGE Energy, Inc.	MGEE	AA-	0.65	0.65	5.00%	6.00%	5.00%	5.00%	99.04%	79.76%	61.62%	77.14%	54.34%
NSTAR	NST	A+	0.69	0.65	6.33%	8.00%	6.25%	6.40%	95.69%	92.85%	83.21%	91.33%	0.00%
Southern Company	SO	A	0.58	0.55	5.00%	4.50%	4.83%	7.50%	98.37%	101.05%	100.00%	100.00%	86.85%

Sources:
[1] Bloomberg
[2] Bloomberg
[3] Value Line
[4] Bloomberg
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] 2006-2008 Annual 10-K Reports
[9] 2006-2008 Annual 10-K Reports
[10] 2006-2008 Annual 10-K Reports
[11] 2006-2008 Annual 10-K Reports
[12] FERC Form 1, pg. 401a; net generation (MWh) / total sources of energy (MWh)

CANADIAN UTILITIES FORECAST AND FINANCIAL DATA

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
	Ticker	Credit Rating	Bloomberg Beta	Value Line Beta	Bloomberg Earnings Growth	Value Line Earnings Growth	Thomson First Call Earnings Growth	Zacks Earnings Growth
Canadian Utilities Limited	CU	A	0.58	--	2.70%	--	--	--
Emera Inc.	EMA	BBB	0.59	--	5.93%	--	--	--
Enbridge Inc.	ENB	A-	0.68	0.65	12.14%	7.50%	11.20%	8.00%
Fortis Inc.	FTS	A-	0.65	--	6.80%	--	--	--
TransCanada Corporation	TRP	A-	0.63	0.85	4.30%	7.00%	5.00%	5.00%

Sources:
[1] Bloomberg
[2] Bloomberg
[3] Value Line
[4] Bloomberg
[5] Value Line
[6] Yahoo! Finance
[7] Zacks

U.S. NATURAL GAS DISTRIBUTION UTILITIES CAPITAL STRUCTURE AS OF DECEMBER 31, 2008

		SHORT-TERM DEBT					LONG-TERM DEBT				PREFERRED STOCK		SHAREHOLDERS' EQUITY				
Company	Ticker	Notes Payable $M	Commercial Paper $M	Short-Term Debt $M	Total $M	%	Current Portion $M	Long-Term Debt $M	Total $M	%	Total $M	%	Minority Interest $M	Common Equity $M	Total $M	%	Total Capital $M
AGL Resources Inc. [1]	AGL	-	-	866	866	20.50%	-	1,675	1,675	39.64%	-	0.00%	32	1,652	1,684	39.86%	4,225
Piedmont Natural Gas Company, Inc. [2]	PNY	407	-	-	407	19.19%	30	794	824	38.92%	-	0.00%	-	887	887	41.89%	2,118
Sempra Energy [3]	SRE	-	-	503	503	3.17%	410	6,544	6,954	43.89%	179	1.13%	240	7,969	8,209	51.81%	15,845
South Jersey Industries, Inc. [4]	SJI	213	-	-	213	19.56%	25	333	358	32.93%	-	0.00%	1	515	516	47.52%	1,087
Southwest Gas Corporation [5]	SWX	-	-	55	55	2.30%	8	1,285	1,293	54.20%	-	0.00%	-	1,038	1,038	43.49%	2,386
Vectren Corporation [6]	VVC	-	-	520	520	16.24%	80	1,248	1,328	41.51%	-	0.00%	0	1,352	1,352	42.25%	3,200
PROXY GROUP MEAN		103	-	324	427	13.49%	92	1,980	2,072	41.85%	30	0.19%	46	2,235	2,281	44.47%	4,810

Sources:
[1] 2008 10-K, pg. 54
[2] 2008 10-K, pg. 74
[3] 2008 10-K, pg. 37
[4] 2008 10-K, pg. 71
[5] 2008 10-K, pg. SJI-40
[6] 2008 10-K, pg. 58

U.S. ELECTRIC DISTRIBUTION COMPANIES CAPITAL STRUCTURE AS OF DECEMBER 31, 2008

		SHORT-TERM DEBT					LONG-TERM DEBT				PREFERRED STOCK		SHAREHOLDERS' EQUITY				
Company	Ticker	Notes Payable $M	Commercial Paper $M	Short-Term Debt $M	Total $M	%	Current Portion $M	Long-Term Debt $M	Total $M	%	Total $M	%	Minority Interest $M	Common Equity $M	Total $M	%	Total Capital $M
CH Energy Group, Inc. [1]	CHG	36	-	-	36	3.50%	20	414	434	42.73%	21	2.07%	1	524	525	51.70%	1,015
Consolidated Edison, Inc. [2]	ED	363	-	-	363	1.82%	482	9,232	9,714	48.60%	213	1.07%	-	9,698	9,698	48.52%	19,988
DPL Inc. [3]	DPL	-	-	-	-	0.00%	176	1,376	1,552	60.85%	23	0.90%	-	976	976	38.25%	2,550
Duke Energy Corporation [4]	DUK	-	-	543	543	1.53%	646	13,250	13,896	39.04%	-	0.00%	163	20,988	21,151	59.43%	35,590
FPL Group, Inc. [5]	FPL	30	1,835	-	1,865	6.48%	1,388	13,833	15,221	52.91%	-	0.00%	-	11,681	11,681	40.61%	28,767
MGE Energy, Inc. [6]	MGEE	-	-	125	125	14.23%	-	272	272	31.13%	-	0.00%	-	478	478	54.64%	875
NSTAR [7]	NST	583	-	-	583	12.00%	98	2,344	2,442	50.28%	43	0.89%	-	1,788	1,788	36.83%	4,856
Southern Company [8]	SO	953	-	-	953	2.91%	617	16,816	17,433	53.24%	1,082	3.30%	-	13,276	13,276	40.54%	32,744
PROXY GROUP MEAN		246	229	83	558	5.31%	428	7,192	7,620	47.35%	173	1.03%	21	7,426	7,447	46.32%	15,798

Source:
[1] 2008 10-K, pg. 101
[2] 2008 10-K, pg. 65
[3] 2008 10-K, pg. 63
[4] 2008 10-K, pg. 86
[5] 2008 10-K, pg. 55
[6] 2008 10-K, pg. 62
[7] 2008 10-K, pg. 53
[8] 2008 10-K, pg. II-53

CANADIAN UTILITIES CAPITAL STRUCTURE AS OF DECEMBER 31, 2008

		SHORT-TERM DEBT					LONG-TERM DEBT				PREFERRED STOCK		SHAREHOLDERS' EQUITY				
Company	Ticker	Notes Payable $M	Commercial Paper $M	Short-Term Debt $M	Total $M	%	Current Portion $M	Long-Term Debt $M	Total $M	%	Total $M	%	Minority Interest $M	Common Equity $M	Total $M	%	Total Capital $M
Canadian Utilities Limited [1]	CU	-		22	22	0.33%	63	3,257	3,319	49.41%	625	9.30%	-	2,752	2,752	40.96%	6,718
Emera Inc. [2]	EMA	-	-	158	158	3.68%	131	2,159	2,291	53.34%	260	6.05%	40	1,546	1,586	36.93%	4,294
Enbridge Inc. [3]	ENB	-	-	875	875	4.24%	719	11,629	12,347	59.83%	125	0.61%	797	6,494	7,291	35.33%	20,638
Fortis Inc. [4]	FTS	-	-	410	410	4.37%	240	4,884	5,124	54.56%	667	7.10%	145	3,046	3,191	33.98%	9,392
TransCanada Corporation [5]	TRP	1,702	-	-	1,702	4.97%	993	17,450	18,443	53.87%	-	0.00%	1,194	12,898	14,092	41.16%	34,237
PROXY GROUP MEAN		340	-	293	633	3.52%	429	7,876	8,305	54.20%	335	4.61%	435	5,347	5,782	37.67%	15,056

Source:
[1] 2008 Canadian Utilities Limited Consolidated Financial Statements, pg. 2
[2] Annual Financial Report 2008, pg. 55
[3] Annual Report 2008, pg. 83
[4] 2008 Annual Report, pg. 81
[5] 2008 Annual Report, pg. 87

Regulatory Risks - Electric Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Volume Variability and Volumetric Protection: May include: Weather Normalization, Revenue Decoupling, Straight Fixed Variable Rate Design, Tiered Rates, etc.	Overall Coverage	Fuel Cost Volatility: Purchased Gas Adjustment, Fuel Cost Pass Through, Timeliness of Recovery	Overall Coverage	Regulatory Lag: Forward Test Year, Forecasted Test Year, Adjusted Historic Test Year, Special Purpose Rate Proceedings, Other	Overall Coverage
Ontario Electric LDCs										
Enersource Hydro Mississauga Inc.		Ontario	670.7	100.00%	Forecasted test year builds in estimate of annual forecasted consumption, utilities may request recovery for volumetric declines in consumption in special proceeding. No weather protection.	medium/ high	Purchased power costs are passed through to end use customer under regulated price plan & spot commodity prices.	medium/ high	Forecast weather normalized load and consumption and test year a plus, decisions come approximately 1 year from filing	medium/ high
Horizon Utilities Corporation		Ontario	98.1	100.00%	Forecasted test year builds in estimate of annual forecasted consumption, utilities may request recovery for volumetric declines in consumption in special proceeding. No weather protection.	medium/ high	Purchased power costs are passed through to end use customer under regulated price plan & spot commodity prices.	medium/ high	Forecast weather normalized load and consumption and test year a plus, decisions come approximately 1 year from filing	medium/ high
Hydro One Networks Inc. (Distribution)		Ontario	2,956.0	100.00%	Forecasted test year builds in estimate of annual forecasted consumption, utilities may request recovery for volumetric declines in consumption in special proceeding. No weather protection.	medium/ high	Purchased power costs are passed through to end use customer under regulated price plan & spot commodity prices.	medium/ high	Forecast weather normalized load and consumption and test year a plus, decisions come approximately 1 year from filing	medium/ high
Hydro Ottawa Limited		Ontario	692.9	100.00%	Forecasted test year builds in estimate of annual forecasted consumption, utilities may request recovery for volumetric declines in consumption in special proceeding. No weather protection.	medium/ high	Purchased power costs are passed through to end use customer under regulated price plan & spot commodity prices.	medium/ high	Forecast weather normalized load and consumption and test year a plus, decisions come approximately 1 year from filing	medium/ high
PowerStream Inc.		Ontario	606.2	100.00%	Forecasted test year builds in estimate of annual forecasted consumption, utilities may request recovery for volumetric declines in consumption in special proceeding. No weather protection.	medium/ high	Purchased power costs are passed through to end use customer under regulated price plan & spot commodity prices.	medium/ high	Forecast weather normalized load and consumption and test year a plus, decisions come approximately 1 year from filing	medium/ high
Toronto Hydro Electric System		Ontario	2,349.5	100.00%	Forecasted test year builds in estimate of annual forecasted consumption, utilities may request recovery for volumetric declines in consumption in special proceeding. No weather protection.	medium/ high	Purchased power costs are passed through to end use customer under regulated price plan & spot commodity prices.	medium/ high	Forecast weather normalized load and consumption and test year a plus, decisions come approximately 1 year from filing	medium/ high
Veridian Connections Inc.		Ontario	228.8	100.00%	Forecasted test year builds in estimate of annual forecasted consumption, utilities may request recovery for volumetric declines in consumption in special proceeding. No weather protection.	medium/ high	Purchased power costs are passed through to end use customer under regulated price plan & spot commodity prices.	medium/ high	Forecast weather normalized load and consumption and test year a plus, decisions come approximately 1 year from filing	medium/ high

Regulatory Risks - Electric Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Financial Stability: Allowed ROE, Equity Ratio, Earnings Sharing Mechanisms, Ring Fencing	Overall Coverage	Escalating Costs: O&M Tracker, Deferral Accounts	Overall Coverage	Major Capital Improvements: CWIP in Rate Base, Preapproval of Construction Costs, Cost Trackers	Overall Coverage	Other Cost Recovery Mechanisms: Cost Recovery through deferral accounts and cost trackers	Overall Coverage
Ontario Electric LDCs												
Enersource Hydro Mississauga Inc.		Ontario	670.7	100.00%	Low Allowed ROE and equity ratio. No financial stability enhancing mechanisms noted	low	IRM escalates revenue requirement by inflation factor less the productivity offset	medium/ high	Capital adjustment mechansim recovers unanticipated material and prudent capex beyond specified threshold - rate rider to fund smart meter program.	high	Z factor in IRM rates provides for recovery of significant events beyond management's control; Rural or Remote Electricity Rate Protection Adjustment rider of $0.13 per KWh; have deferral accounts for lost revenues and shared savings attributable to CDM programs, Board declined accountng transition deferral account and environmental compliance tracking account; deferral accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate the distributor is authorized to bill its customers	medium/ high
Horizon Utilities Corporation		Ontario	98.1	100.00%	Low Allowed ROE and equity ratio. No financial stability enhancing mechanisms noted	low	IRM escalates revenue requirement by inflation factor less the productivity offset	medium/ high	Capital adjustment mechansim recovers unanticipated material and prudent capex beyond specified threshold - rate rider to fund smart meter program.	high	Z factor in IRM rates provides for recovery of significant events beyond management's control; Deferral accounts for regulatory asset recovery, settlement variances between amount charged by the Independent ISO and amounts billed to customers, and for operating and capital costs related to the smart meter program	medium/ high
Hydro One Networks Inc. (Distribution)		Ontario	2,956.0	100.00%	Equity ratio of 40% with an authorized ROE of 8.01%. No financial stability enhancing mechanisms noted	low	IRM escalates revenue requirement by inflation factor less the productivity offset	medium/ high	Capital adjustment mechansim recovers unanticipated material and prudent capex beyond specified threshold - rate rider to fund smart meter program.	high	Z factor in IRM rates provides recovery of signficant events beyond management's control - Conservation and smart metering recovered through monthly surcharge - Revenue difference deferral account records differences between existing and anticipated transmissin rates w/ recovery over 27 month period - No weather protection various deferral accounts: environmental recovery, pension, regulatory assets and liabilities, wheeling and export fees	high
Hydro Ottawa Limited		Ontario	692.9	100.00%	Equity ratio of 40% with an authorized ROE of 8.01%. 300 basis point trigger above or below 8.57 percent, for a review of new cost of service application	low	IRM escalates revenue requirement by inflation factor less the productivity offset	medium/ high	Capital adjustment mechansim recovers unanticipated material and prudent capex beyond specified threshold - rate rider to fund smart meter program.	high	Z factor in IRM rates provides recovery of signficant events beyond management's control; deferral accounts include retail services and settlement variances; deferred smart meter costs; PIL corpate taxes; and others	high
PowerStream Inc.		Ontario	606.2	100.00%	Equity ratio of 40% with an authorized ROE of 8.01%. No financial stability enhancing mechanisms noted	low	IRM escalates revenue requirement by inflation factor less the productivity offset	medium/ high	Capital adjustment mechansim recovers unanticipated material and prudent capex beyond specified threshold - rate rider to fund smart meter program.	high	Z factor in IRM rates provides recovery of signficant events beyond management's control; has requested deferral account in 2009 for retail settlement variances, which represents an over-collection of renergy and transmission costs	medium/ high
Toronto Hydro Electric System		Ontario	2,349.5	100.00%	Equity ratio of 40% with an authorized ROE of 8.01%. No financial stability enhancing mechanisms noted	low	IRM escalates revenue requirement by inflation factor less the productivity offset	medium/ high	Capital adjustment mechansim recovers unanticipated material and prudent capex beyond specified threshold - rate rider to fund smart meter program.	high	Z factor in IRM rates provides recovery of significant events beyond management's control; primary deferral account in 2008 was for smart meter investments, past deferral account for payment in lieu of corporate income tax	medium/ high
Veridian Connections Inc.		Ontario	228.8	100.00%	Equity ratio of 40% with an authorized ROE of 8.01%. No financial stability enhancing mechanisms noted	low	IRM escalates revenue requirement by inflation factor less the productivity offset	medium/ high	Capital adjustment mechansim recovers unanticipated material and prudent capex beyond specified threshold - rate rider to fund smart meter program.	high	Z factor in IRM rates provides recovery of significant events beyond management's control; regulatory deferral accounts to record the Corporation's incremental OEB cost assessments and pension costs that would otherwise have been charged to results of operations.	medium/ high

Regulatory Risks - Electric Utilities

					Volume Variability and Volumetric Protection		Fuel Cost Volatility		Regulatory Lag	
Regulatory Mechanisms	**Ticker**	**State/ Province**	**Revenue**	**% of Total Revenue**	**May include: Weather Normalization, Revenue Decoupling, Straight Fixed Variable Rate Design, Tiered Rates, etc.**	**Overall Coverage**	**Purchased Gas Adjustment, Fuel Cost Pass Through, Timeliness of Recovery**	**Overall Coverage**	**Forward Test Year, Forecasted Test Year, Adjusted Historic Test Year, Special Purpose Rate Proceedings, Other**	**Overall Coverage**
Average Ontario Electric Dist. Utility										
U.S. Electric LDCs										
CH Energy Group, Inc.	CHG		1,338.1	100.00%						
Central Hudson Gas & Electric Corp.		NY	798.0	59.64%	Revenue Decoupling Mechanism for conservation loss only	medium/ high	No fuel risk due to competitive market; POLR straight pass through	high	fully forecasted test period. In the context of adopting multi-year rate plans, the PSC has allowed rate base to be updated each year.	high
Consolidated Edison, Inc.	ED									
Consolidated Edison Company of New York, Inc.		NY	10,573.1	100.00%	Revenue decoupling mechansims (RDM) approved but does not protect against weather risk	medium/ high	No fuel risk due to competitive market	high	fully forecasted test period. In the context of adopting multi-year rate plans, the PSC has allowed rate base to be updated each year.	high

Regulatory Risks - Electric Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Financial Stability: Allowed ROE, Equity Ratio, Earnings Sharing Mechanisms, Ring Fencing	Overall Coverage	Escalating Costs: O&M Tracker, Deferral Accounts	Overall Coverage	Major Capital Improvements: CWIP in Rate Base, Preapproval of Construction Costs, Cost Trackers	Overall Coverage	Other Cost Recovery Mechanisms: Cost Recovery through deferral accounts and cost trackers	Overall Coverage
Average Ontario Electric Dist. Utility												
U.S. Electric LDCs												
CH Energy Group, Inc.	CHG		1,338.1	100.00%	See notes							
Central Hudson Gas & Electric Corp.		NY	798.0	59.64%	Equity ratio of 47% with an authorized ROE of 10%; include an incentive related to retail customer switching rates or the level of customers' understanding of retail choice. Orange and Rockland Utilities' current gas rate plan provides for the sharing of earnings in excess of an 11% ROE; however, this threshold is reduced to 10.8% if during any rate year the company fails to earn the "Retail Choice Customer Understanding Incentive."	medium/ high	Forecasted test year, rates updated each year for multi-year plan.	medium/ high	PSC has generally permitted companies to include CWIP in rate base on a case by case basis.	medium	PSC authorized the company to defer certain items, with recovery to occur in the next rate case: incremental pension expense; post employment benefits other than pensions; interest on variable rate debt; incremental costs of litigation regarding claims of exposure to asbestos at company facilities; research and development costs; property taxes; changes in accounting standards; changes in federal or state regulations that have an impact of more than 1% of net gas or electric income; and, stray voltage program expense. The company can defer 100% of these items to if it earns below an 11% ROE. However, the ability to defer expenses is to be limited if CHG&E earns within an ROE range of 11%-to-14%. The company would be required to reduce, by up to 50%, the deferral of certain expenses (including stray voltage costs, property taxes, interest on variable rate debt, and asbestos litigation costs), provided that such reduction in deferrals will not cause earnings to decrease below an 11% ROE.	high
Consolidated Edison, Inc.	ED											
Consolidated Edison Company of New York, Inc.		NY	10,573.1	100.00%	Equity ratio is 48% with an authorized ROE of 10%, Incentive rate plan with earnings sharing	medium/ high	Forecasted test year, rates updated each year for multi-year plan.	medium/ high	PSC has generally permitted companies to include CWIP in rate base on a case by case basis.	medium	Renewable Portfolio Standard cost recovery pass-through. PSC authorized the company to defer certain items, with recovery to occur in the next rate case: incremental pension expense; post employment benefits other than pensions; interest on variable rate debt; incremental costs of litigation regarding claims of exposure to asbestos at company facilities; research and development costs; property taxes; changes in accounting standards; changes in federal or state regulations that have an impact of more than 1% of net gas or electric income; and, stray voltage program expense. The company can defer 100% of these items to if it earns below an 11% ROE. However, the ability to defer expenses is to be limited if CHG&E earns within an ROE range of 11%-to-14%. The company would be required to reduce, by up to 50%, the deferral of certain expenses (including stray voltage costs, property taxes, interest on variable rate debt, and asbestos litigation costs), provided that such reduction in deferrals will not cause earnings to decrease below an 11% ROE.	high

Regulatory Risks - Electric Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Volume Variability and Volumetric Protection: May include: Weather Normalization, Revenue Decoupling, Straight Fixed Variable Rate Design, Tiered Rates, etc.	Overall Coverage	Fuel Cost Volatility: Purchased Gas Adjustment, Fuel Cost Pass Through, Timeliness of Recovery	Overall Coverage	Regulatory Lag: Forward Test Year, Forecasted Test Year, Adjusted Historic Test Year, Special Purpose Rate Proceedings, Other	Overall Coverage
Orange & Rockland Utilities, Inc.		NY	777.6	7.35%	Revenue decoupling mechanism (RDM) to remove impact of fluctuations on earnings caused by variation in customer usage due to weather or energy effeciency programs.	high	No fuel risk due to competitive market	high	fully forecasted test period. In the context of adopting multi-year rate plans, the PSC has allowed rate base to be updated each year.	high
Pike County Light & Power Company		PA	7.2	0.07%	No information available		No fuel risk due to competitive market	high	In accordance with state statutes, the PUC has generally relied on a depreciated original-cost year end rate base for a forecasted test year that is historical by the time a case is decided.	medium/ high
Rockland Electric Company		NJ	237.7	2.25%	None noted	low	All fuel costs passed through immediately to customers	high	historical year-end original cost rate base. Most cases are filed utilizing partly projected data, with known-and-measurable changes permitted. Partially forecasted test year.	medium
DPL Inc.	DPL		1,604.2	100.00%						
Dayton Power and Light Company		OH	1,656.6	103.27%	None noted	low	RSP Provides full capacity and purchased power pass through to customers as well as protection for POLR obligations	high	Ohio law requires utilization of an original cost rate base valued as of a date certain, which can be no later than the date the rate case is filed. Statutes require that the test year conclude within nine months after the filing of a rate increase application.	low
Duke Energy Corporation	DUK		13,397.0	100.00%						
Duke Energy Carolinas, LLC		NC, SC	5,881.8	43.90%	None noted	low	Prudent fuel cost are recovered through fuel adjustment clause (FAC). Each utility has annual hearing to review fuel costs with true-up of any over- or under-collections from the previous year, with interest included only for over-collections.	medium/ high	year-end original-cost rate base for a historic test period, consider changes that are known and quantifiable prior to the close of hearings.	low/ medium

Regulatory Risks - Electric Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Financial Stability: Allowed ROE, Equity Ratio, Earnings Sharing Mechanisms, Ring Fencing	Financial Stability: Overall Coverage	Escalating Costs: O&M Tracker, Deferral Accounts	Escalating Costs: Overall Coverage	Major Capital Improvements: CWIP in Rate Base, Preapproval of Construction Costs, Cost Trackers	Major Capital Improvements: Overall Coverage	Other Cost Recovery Mechanisms: Cost Recovery through deferral accounts and cost trackers	Other Cost Recovery Mechanisms: Overall Coverage
Orange & Rockland Utilities, Inc.		NY	777.6	7.35%	Three-year electric rate settlement based a 48% equity ratio and a 9.4% ROE. Earnings above a 10.2% ROE are to be shared in varying degrees by ratepayers and shareholders	medium/ high	Forecasted test year, rates updated each year for multi-year plan.	medium/ high	PSC has generally permitted companies to include CWIP in rate base on a case by case basis.	medium	Temporary State Adjusment Surcharge: Reconciles difference between forecast and actual Section 18-a amounts collected. Cost recovery for renewable portfolio standards, merchant function charge, and an adjustment for the transition to competitive services. PSC authorized the company to defer certain items, with recovery to occur in the next rate case: incremental pension expense; post employment benefits other than pensions; interest on variable rate debt; incremental costs of litigation regarding claims of exposure to asbestos at company facilities; research and development costs; property taxes; changes in accounting standards; changes in federal or state regulations that have an impact of more than 1% of net gas or electric income; and, stray voltage program expense. The company can defer 100% of these items to if it earns below an 11% ROE. However, the ability to defer expenses is to be limited if CHG&E earns within an ROE range of 11%-to-14%. The company would be required to reduce, by up to 50%, the deferral of certain expenses (including stray voltage costs, property taxes, interest on variable rate debt, and asbestos litigation costs), provided that such reduction in deferrals will not cause earnings to decrease below an 11% ROE.	high
Pike County Light & Power Company		PA	7.2	0.07%	No information available		Forecasted test year, rates updated each year for multi-year plan.	medium/ high	No information available		No information available	
Rockland Electric Company		NJ	237.7	2.25%	Equity ratio of 46.51% with a 9.75% ROE.	low/ medium	Partially forecasted tet year	medium	PSC has generally permitted companies to include CWIP in rate base on a case by case basis and cash flow issues arise.	medium/ high	NJ energy efficiency program is now known as NJ Clean Energy (NJCE). Costs associated with the NJCE program are recovered through a non-bypassable societal benefits charge on customer bills. BPU approved accelerated infrastructure programs for utilities that had filed such plans. For the most part the costs of these programs are to be recovered through separate adjustment mechanisms.	medium/ high
DPL Inc.	DPL		1,604.2	100.00%								
Dayton Power and Light Company		OH	1,656.6	103.27%	ROE has been set at 13 percent since 1992	medium/ high	RSP plan provides that company may get actual recovery of costs by applying to PUC	low/ medium	State law provides for allowance of construction work in progress (CWIP) in rate base at the PUC's discretion if a project is 75% complete. However, the proportion of non-pollution-control CWIP that the PUC may include in rate base is limited to 10% of rate base excluding CWIP. Pollution control projects may be included to bring the total percentage of CWIP to a maximum of 20% of rate base.	medium/ high	In December 2005, the PUC approved a stipulation providing for DP&L to: implement an RSC equal to 11% of tariffed rates as of Jan. 1, 2004; extend the RSP to year-end 2010; implement increased "market-based" generation rates in 2009 through the elimination of the existing 5% residential generation discount; and, implement an Environmental Investment Rider (EIR) in 2007. The EIR is to allow DP&L to recover environmental plant investment and associated operation and maintenance expenses during the RSP. Beginning on Jan. 1 of each year, from 2007 through 2010, the EIR is to rise by 5.4% of DP&L's Jan. 1, 2004 tariffed generation rates.	medium/ high
Duke Energy Corporation	DUK		13,397.0	100.00%								
Duke Energy Carolinas, LLC		NC, SC	5,881.8	43.90%	ROE is 11%	medium	None noted	low	CWIP in rate base; NCUC to pre-determine the prudence of a utility's decision to build a baseload generating facility and the plant's projected costs. Subject to annual filing, the utility would be permitted to recover previously approved costs in rates. If plant construction is not completed because of an unavoidable or unforeseen change in circumstances, the utility would be permitted to recover prudently incurred costs.	medium	Cost recovery for DSM costs, energy efficiency programs, merger savings, residential load control, pilot solar programs, and net metering.	medium/ high

Regulatory Risks - Electric Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Volume Variability and Volumetric Protection: May include: Weather Normalization, Revenue Decoupling, Straight Fixed Variable Rate Design, Tiered Rates, etc.	Overall Coverage	Fuel Cost Volatility: Purchased Gas Adjustment, Fuel Cost Pass Through, Timeliness of Recovery	Overall Coverage	Regulatory Lag: Forward Test Year, Forecasted Test Year, Adjusted Historic Test Year, Special Purpose Rate Proceedings, Other	Overall Coverage
Duke Energy Indiana, Inc.		IN	2,480.7	18.52%	None noted	low	Electric utilities may adjust rates for changes in fuel and purchased power (energy component only) costs every three months, following hearings, through the fuel adjustment clause (FAC). Recovery subject to limitation that it cannot result in (NOI) in excess of that authorized. that is to remain in place until the company's next base rate proceeding. The fuel component of purchased power is to be recovered through the FAC.	medium	Indiana is statutorily a fair-value state. URC has, in most instances, calculated its fair-value rate base and return findings after having determined a return on original-cost rate base on the basis of an historical test period and a test year-end rate base, with adjustments for known-and-measurable changes expected to occur within one year after the end of the test period.	medium/ high
Duke Energy Kentucky, Inc.		KY	500.1	3.73%	Straight Fixed Variable Rate Design (pending).	low	PSC has allowed fuel and purchased power (energy only) costs to be recovered through automatic fuel adjustment clauses (FACs). Adjustments are implemented monthly, based on actual costs for the second preceding month (producing a two-month lag), with an under- or over-recovery mechanism included in the clause.	high	year-end rate base for a historical test period, adjusted for known-and-measurable changes. However, statutes permit the utilities to employ forecasted test periods.	medium
Duke Energy Ohio, Inc.		OH	3,167.4	23.64%	Straight Fixed Variable Rate Design	high	RSP Provides full capacity and purchased power pass through to customers annually as well as protection for POLR obligations	high	Ohio law requires utilization of an original cost rate base valued as of a date certain, which can be no later than the date the rate case is filed. Statutes require that the test year conclude within nine months after the filing of a rate increase application.	low
FPL Group, Inc.	FPL		16,487.0	100.00%						
Florida Power & Light Company		FL	11,646.8	70.64%	Fully forecasted test year	medium	The fuel and purchased power cost recovery clause (FPPCR) provides for recovery of prudently incurred fuel and purchased power costs, based upon 12-month projections of fuel costs and energy purchases and sales. Hearings are held in November, during which the PSC sets fuel factors for the next calendar year.	medium/ high	In permanent base rate case decisions, the PSC generally has utilized test periods that are fully or partially forecasted at the time the rate decisions are issued.	medium/ high
MGE Energy Group, Inc.	MGEE		604.0	100.00%						

Regulatory Risks - Electric Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Financial Stability: Allowed ROE, Equity Ratio, Earnings Sharing Mechanisms, Ring Fencing	Overall Coverage	Escalating Costs: O&M Tracker, Deferral Accounts	Overall Coverage	Major Capital Improvements: CWIP in Rate Base, Preapproval of Construction Costs, Cost Trackers	Overall Coverage	Other Cost Recovery Mechanisms: Cost Recovery through deferral accounts and cost trackers	Overall Coverage
Duke Energy Indiana, Inc.		IN	2,480.7	18.52%	Share in earnings from off-system sales with ratepayers. Currently approved return is 10.5% and 44.44% equity. Incentives for meeting energy efficiency targets. DEI is to equally share with ratepayers off-system sales (OSS) margins that vary from the $14.7 million amount included in the company's revenue requirement.	medium	fair value rate base; full recovery of O&M costs associated with environmental compliance	high	URC rules require that a utility may file for rate base inclusion of pollution control-related CWIP; URC approved a certificate of need for Duke Energy Indiana (DEI) to construct a 630-MW integrated gasification combined-cycle plant in Indiana and authorized DEI to earn a cash return on CWIP during construction. Revenue adjustments provided for Integrated Coal Gasification CC Generating Facilities; Pollution Control costs; SO2 and Nox Emission Allowances;	medium/ high	Revenue Adjustments for: DSM Adjustments; Amortization of Merger Costs; MISO costs; Clean Coal Operation Costs. Smart grid cost tracking proposal (pending). DEI to recover the costs associated with a new environmental compliance plan through the company's semi-annually adjusted standard contract riders (SCRs). The settlement provides for recovery of capital investment expected for DEI's environmental compliance plan , and associated financing, construction, operation and maintenance (O&M), and depreciation costs, through the SCRs, appropriate return; (2) recovery through the SCRs of emission allowance costs incurred to comply with the federal environmental regulations; (3) DEI to accrue post-in-service AFUDC and to defer depreciation and O&M expenses until these costs are reflected in base rates; (4) the use of a 20-year accelerated depreciation period for such projects; and, (5) the use of a negative net salvage factor of 10% for such projects. Through this mechanism, the utilities are also authorized to recover related O&M and depreciation expenses after the environmental facilities become operational. Recovery of demand charges through a summer reliability tracking mechanism	high
Duke Energy Kentucky, Inc.		KY	500.1	3.73%	11.5%, share profits of off system sales with ratepayers	medium	None noted	low	The electric utilities have historically been allowed to include virtually all construction work in progress in rate base for a cash return.	medium/ high	Revenue Adjustments for: Brownfield redevelopment, Green Power usage, Merger Savings Credit, and Development incentives.	low/ medium
Duke Energy Ohio, Inc.		OH	3,167.4	23.64%	Special purpose ROEs for calculating certain rates.	medium	RSP plan provides that company may get actual recovery of costs by applying to PUC	low/ medium	State law provides for allowance of construction work in progress (CWIP) in rate base at the PUC's discretion if a project is 75% complete. However, the proportion of non-pollution-control CWIP that the PUC may include in rate base is limited to 10% of rate base excluding CWIP. Pollution control projects may be included to bring the total percentage of CWIP to a maximum of 20% of rate base.	medium/ high	The approved RSP included the following: (1) the creation of an infrastructure maintenance fund; (2) implementation of a system reliability tracker (SRT), under which Duke is to annually apply to the PUC to purchase power to cover peak and reserve capacity requirements and to flow through those costs to customers; (3) increased customer avoidability for both the RSC, which is related to the risk associated with customers returning from competitive providers, and an annually adjusted component (AAC), which would allow the company to maintain adequate capacity reserves and to recover costs associated with homeland security, taxes, environmental compliance, and emission allowances; (4) making emissions allowance charges fully avoidable; and, (5) setting increases to the AAC for non residential customers at 4% of "little g" in 2005, and an additional 4% of "little g" in 2006, with Duke to be permitted to apply for additional recovery of actual costs in 2007 and 2008.	high
FPL Group, Inc.	FPL		16,487.0	100.00%								
Florida Power & Light Company		FL	11,646.8	70.64%	FP&L is operating under a four-year rate plan approved in 2005. An 11.75% return on equity (ROE) will be utilized "for all other regulatory purposes," and FP&L may request a rate increase if base rate earnings fall below a 10% ROE. PSC provides for 20% of profits from energy sales to be retained by the companies. in the fuel adjustment clause is a generating performance incentive factor (GPIF). The GPIF provides a financial reward or penalty (25 bps) when a company's base load generating units' availability and heat rate vary from targets approved by the PSC.	high	PSC uses test periods that are fully or partially forecasted at the time the rate decisions are issued.	medium/ high	deferred accounting for the preconstruction costs of nuclear and IGCC plants, and these costs are to accrue a carrying charge equal to the utility's allowance for funds used during construction (AFUDC). All prudently incurred preconstruction costs are recoverable through the utility's capacity cost recovery clause. Also recoverable through the capacity cost recovery clause is a current cash return on CWIP.	high	Storm damage reserve. Also has cost recovery clauses for environmental and energy effeciency costs. Certain fees and taxes, such as franchise fees and gross receipts taxes, are recovered through a line item on customer bills, with the charge adjusted based on customer usage.	medium/ high
MGE Energy Group, Inc.	MGEE		604.0	100.00%								

Regulatory Risks - Electric Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Volume Variability and Volumetric Protection: May include: Weather Normalization, Revenue Decoupling, Straight Fixed Variable Rate Design, Tiered Rates, etc.	Overall Coverage	Fuel Cost Volatility: Purchased Gas Adjustment, Fuel Cost Pass Through, Timeliness of Recovery	Overall Coverage	Regulatory Lag: Forward Test Year, Forecasted Test Year, Adjusted Historic Test Year, Special Purpose Rate Proceedings, Other	Overall Coverage
Madison Gas and Electric Company		WI	631.5	104.55%	Fully or partially forecasted test year	medium	Annual fuel and purchased power costs are trued up against forecast. If a company's actual fuel and purchased power costs are outside a monthly or cumulative monthly variance range around the forecasts, and the utility can demonstrate that these costs will likely be outside the annual range, the PSC may conduct a hearing to establish new rates. Currently, the annual variance range is plus or minus 2% for the state's utilities.	medium/ high	The PSC generally relies on an average original-cost rate base and a test period that is fully or close to fully-forecasted when the new rates become effective.	medium/ high
NSTAR	NST		3,357.6	100.00%						
NSTAR Electric Company		MA	2,902.4	86.44%	Nstar is eligible for full decoupling, and will be implenting a full decoupling mechanism in its next rate proceeding	high	No fuel risk due to competitive market	high	In traditional rate cases, a historical test year and a year-end original-cost rate base, adjusted for known-and-measurable changes, are utilized. Post test-year rate base additions have been permitted only for "significant" investment that has a "substantial" effect on rate base.	medium
Southern Company	SO		17,209.0	100.00%						
Alabama Power Company		AL	6,087.4	35.37%	Rate Stabilization and Equalization Factor allows incorporation of projected data to set rates	medium	An Energy Cost Recovery system is in place for Alabama Power. The ECR system is established on the basis of estimates of electric sales, fuel, and net purchased energy costs, and reflects accumulated over- or under-recovered amounts. Alabama Power may recover specific costs associated with purchases of natural gas for its electric generating facilities, including the cost of financial tools used for hedging market price risk for up to 75% of the budgeted annual amount of natural gas purchases. The company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5% of the company's natural gas budget for that year.	medium/ high	Alabama statutes provide for use of a historical test year, adjusted for known-and-measurable changes. However Rate Stabilization and Equalization RSE adjustments incorporate estimates of forward returns for the upcoming year into current rates, adjusting rates upwards or downwards according to specified thresholds.	medium/ high
Georgia Power Company		GA	8,546.4	49.66%	electric and natural gas companies file rate cases based on projected data, and the PSC relies on average rate bases. Electric and natural gas rate case test years must be partially forecasted at the time of decision	medium	Non-automatic fuel adjustment mechanism. Hearings are required before increases are implemented. Electric fuel rates are based on estimated sales and fuel costs, and any balance of previously unrecovered/over-recovered fuel costs is considered in setting new rates. The energy portion of purchased power transactions is reflected in the mechanism; the capacity component is recovered through base rates.	medium/ high	Georgia Power files rate cases based on projected data, and the PSC relies on average rate bases. Test years must be partially forecasted at the time of decision.	high
Gulf Power Company		FL	1,387.4	8.06%	Fully forecasted test year	medium	The fuel and purchased power cost recovery clause (FPPCR) provides for recovery of prudently incurred fuel and purchased power costs. Annual fuel factors are established based upon 12-month projections of fuel costs and energy purchases and sales. Hearings are held in November, during which the PSC sets fuel factors for the next calendar year. Subsequent to the November hearings, utilities may seek, or the PSC may require, a mid-term modification to the factors if updated projected costs for the year vary significantly from updated projected revenues. Interest is accrued on both over- and under recovered balances.	medium/ high	The PSC generally relies on an average original-cost rate base. In permanent base rate case decisions, the PSC generally has utilized test periods that are fully or partially forecasted at the time the rate decisions are issued.	medium/ high

Regulatory Risks - Electric Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Financial Stability: Allowed ROE, Equity Ratio, Earnings Sharing Mechanisms, Ring Fencing	Overall Coverage	Escalating Costs: O&M Tracker, Deferral Accounts	Overall Coverage	Major Capital Improvements: CWIP in Rate Base, Preapproval of Construction Costs, Cost Trackers	Overall Coverage	Other Cost Recovery Mechanisms: Cost Recovery through deferral accounts and cost trackers	Overall Coverage
Madison Gas and Electric Company		WI	631.5	104.55%	Working capital is not included in rate base, but the PSC allows for a return on working capital through an adder to the return on rate base. Authorized return is 10.8% on 57.36% equity.	medium/ high	forecasted test period	medium/ high	Through a return adder, the PSC generally allows a current return on 50% of a utility's electric and gas construction work in progress (CWIP), except for major generation projects for which the PSC generally allows a current return on 100% of the CWIP associated with that project. State law permits a utility that is proposing to purchase or construct an electric generating facility to apply to the PSC for an order specifying, in advance, the rate treatment, including the equity return, that will apply to the plant over its economic life and inclusion in rate base of the facility.	medium/ high	Riders for renewable energy programs and alternative generation.	medium
NSTAR	NST		3,357.6	100.00%								
NSTAR Electric Company		MA	2,902.4	86.44%	NSTAR Electric is operating under an electric performance-based regulation (PBR) plan that contains provisions under which earnings outside of an 8.5%-to-12.5% ROE range are to be shared with ratepayers . Incentives for meeting efficiency targets.	medium/ high	PBR plan has escalation of rates based on GDP price Index less a productivity factor	medium/ high	Riders for renewable energy and energy effeciency programs, and transition costs. Electric utilities operating in the state have transmission cost recovery mechanisms.	medium	Reconciliation mechanisms are in effect for recovery of low-income discounts rates and for the recovery of administrative costs (e.g., employee costs and bad debt) incurred in providing basic service. In 2003, the Department adopted pension and post-retirement benefits other than pensions (PBOP) adjustment mechanisms for Boston Gas, NSTAR Electric and NSTAR Gas.	medium
Southern Company	SO		17,209.0	100.00%								
Alabama Power Company		AL	6,087.4	35.37%	Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If Alabama Power's projected ROE is outside the allowed ROE range of 13% to 14.5%, rates are to be adjusted, subject to the following limits on rate increases, to establish a 13.75%. Any annual rate increase is limited to 5%, and rate increases for any two-year period, when averaged, cannot exceed 4% per year.	high	Rate Stabilization and Equalization Mechanisms incorporates projections of costs for the upcoming year.	medium/ high	The Certificated New Plant (Rate CNP) adjustment clause for Alabama Power provides for: the certification of generating facilities and the recovery of related costs; the certification of purchased power agreements and recovery of the costs (excluding fuel) associated with each agreement; and, recovery of costs associated with environmental mandates. Cost recovery by Alabama Power under Rate CNP generally involves a Staff and PSC review process and public meetings. Evidentiary hearings are also held in conjunction with the certification of generating facilities and purchased power agreements.	medium/ high	Alabama Power is authorized to recover nuclear decommissioning costs from ratepayers. Alabama power is allowed to maintain a natural disaster reserve. Environmental Cost Recovery Mechanism.	medium
Georgia Power Company		GA	8,546.4	49.66%	Earnings sharing, inewill continue to be evaluated against a retail ROE range of 10.25% to 12.25%. One-third of any earnings above 12.25% are to be credited first to any environmental compliance cost recovery (ECCR) deferrals and then to accelerate the depreciation of environmental costs, and two-thirds are to be refunded to customers. PSC approved six new demand-side management programs that will enable the company to retain 15% of the net present value of the net benefits generated by the programs.	medium/ high	rate cases based on projected data. Test years must be partially forecasted at the time of decision	medium/ high	Georgia Power earns a cash return on CWIP associated with planned nuclear plants that have been certified by the PSC, was enacted. PSC authorized GP to implement an environmental compliance cost recovery (ECCR) tariff for 2008, 2009, and 2010 that permits the company to recover costs related to environmental controls mandated by state and federal regulations.	medium	Case by case basis, GP is authorized, under certain conditions, to transfer "other Costs of Removal" funds from accumulated depreciation to a regulatory liability account, and then to amortize this liability. This accounting treatment reduces company expenses, and does not involve a rate increase	low/ medium
Gulf Power Company		FL	1,387.4	8.06%	Gulf Power (GP) is authorized an 11.75% equity return, the mid-point of an allowed range of 10.75% to 12.75%, as established by the PSC in 2002. For rate-setting purposes, however, a 12% ROE was utilized to reflect the company's provision of superior service. PSC provides for 20% of profits from energy sales to be retained by the companies. in the fuel adjustment clause is a generating performance incentive factor (GPIF). The GPIF provides a financial reward or penalty (25 bps) when a company's base load generating units' availability and heat rate vary from targets approved by the PSC.	high	Forecasted revenue requirement	medium/ high	Deferred accounting for the preconstruction costs of nuclear and IGCC plants, and these costs are to accrue a carrying charge equal to the utility's allowance for funds used during construction (AFUDC). All prudently incurred preconstruction costs are recoverable through the utility's capacity cost recovery clause. Also recoverable through the capacity cost recovery clause is a current cash return on CWIP.	high	Storm damage reserve. Also has cost recovery clauses for environmental and energy effeciency costs. Certain fees and taxes, such as franchise fees and gross receipts taxes, are recovered through a line item on customer bills, with the charge adjusted based on customer usage.	medium/ high

Regulatory Risks - Electric Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Volume Variability and Volumetric Protection		Fuel Cost Volatility		Regulatory Lag	
					May include: Weather Normalization, Revenue Decoupling, Straight Fixed Variable Rate Design, Tiered Rates, etc.	Overall Coverage	Purchased Gas Adjustment, Fuel Cost Pass Through, Timeliness of Recovery	Overall Coverage	Forward Test Year, Forecasted Test Year, Adjusted Historic Test Year, Special Purpose Rate Proceedings, Other	Overall Coverage
Mississippi Power Company		MS	1,264.7	7.35%	Forward looking test year	medium	PSC rules provide for automatic electric fuel adjustment clauses, with the energy component of purchased power recovered through the fuel clause and the capacity component recovered in base rates. Mississippi Power (MP) uses levelized fuel adjustment clauses based upon projected fuel use and costs, with a provision for the reconciliation of over- and under-recoveries. MP's fuel adjustment is set for a 12-month period. The PSC must conduct an annual audit of all fuel purchases and interchange contracts and submit an annual report to the Legislature. MP also has separate energy cost management clauses to recover fuel hedging gains, losses, and expenses.	medium/ high	Alternative rate plan (ARP) in effect for MP provides for annual rate reviews. MP's plan utilizes a forward-looking test year and a year-end rate base in each review,	medium/ high

Regulatory Risks - Electric Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Financial Stability: Allowed ROE, Equity Ratio, Earnings Sharing Mechanisms, Ring Fencing	Financial Stability: Overall Coverage	Escalating Costs: O&M Tracker, Deferral Accounts	Escalating Costs: Overall Coverage	Major Capital Improvements: CWIP in Rate Base, Preapproval of Construction Costs, Cost Trackers	Major Capital Improvements: Overall Coverage	Other Cost Recovery Mechanisms: Cost Recovery through deferral accounts and cost trackers	Other Cost Recovery Mechanisms: Overall Coverage
Mississippi Power Company		MS	1,264.7	7.35%	Equity ratio of 53.68%. MP operates under a formula-based alternative rate plan. An 11.6% ROE became effective in January 2008 under MP's ARP. The ARP employs an incentive based earnings sharing mechanism. MP's benchmark return on equity (ROE) is calculated annually as of September 30, based upon an equal weighting of the following methodologies--discounted cash flow, risk premium, and a capital asset pricing model--plus a 25-basis-point flotation cost premium	high	Forward looking test year, annual rate base review	medium/ high	The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. PSC to permit rate recovery of all prudently incurred preconstruction, construction, and operating costs of new base-load coal-fired generation facilities of at least 300 MW and nuclear facilities of at least 800 MW, including a current cash return on CWIP. Recovery of relevant expenses can be permitted, whether or not the facility's construction is commenced or completed.	medium/ high	Mississippi Power is authorized to have a storm damage reserve of $60m. MP has utilized an Environmental Compliance Overview (ECO) plan. The ECO plan provides for base-rate recovery of costs (including the cost of capital) associated with PSC-approved environmental projects, on an annual basis, outside of a base rate case. Under the ECO plan, any increase in annual revenue requirement is limited to 2% of retail revenues. However, the plan also provides for carryover of any amount over the 2% limit into the next year's revenue requirement.	medium/ high

Regulatory Risks - Natural Gas Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Volume Variability and Volumetric Protection: May include: Weather Normalization, Revenue Decoupling, Straight Fixed Variable Rate Design, Tiered Rates, etc.	Volume Variability and Volumetric Protection: Overall Coverage	Fuel Cost Volatility: Purchased Gas Adjustment, Fuel Cost Pass Through, Timeliness of Recovery	Fuel Cost Volatility: Overall Coverage
Ontario Gas LDCs								
Enbridge Inc.	ENB		16,131.3	100.00%				
Enbridge Gas Distribution Inc.		Ontario	3,011.0	18.67%	Declining average use per customer is minimized through an incentive regulation plan via a revenue per customer cap. Enbridge does not have protection against fluctuations in earnings cased by changes in weather. However, they do revise their revenue forecast based on updated weather projections as it relates to heating degree days. In addition to updating the volumetric forecast annually based on expected weather and economic conditions for the test year, the Company also has an average use true up variance account "AUTUVA" trues up for the monetary/rate impact, exclusive of gas costs, of any deviations between normalized actual and forecast average use. Essentially, a conservation decoupling mechanism. Additionally, Enbridge is allowed to increase its fixed monthly customer charge throughout the term of the IR plan, resulting in less exposure to to weather.	medium/ high	Cost of gas is passed through to customers using the Quarterly Rate Adjustment Mechanism.	high
Spectra Energy Corporation	SE		5,074.0	100.00%				
Union Gas Limited		Ontario	2,130.0	41.98%	Over the past number of years, the Board has approved increases to the fixed monthly charge for Union. In the settlement, all parties accepted Union Gas' implementation of the Board's directed weather normalization methodology (55% of 30-year average and 45% of 20-year declining trend estimate). Union also has an adjustment factor adjusting for changes in weather normalized average use. The average use mechanisms reduces the volume used to determine rates by the average of the most recent three years' actual weather normalized volume loss (using the 55/45 blended weather method, updated annually) per general service customer within each rate class. Further, there is a deferral account to capture the variance between forecast use per customer declines (based on the three year historical average) and what is observed on an actual basis.	medium/ high	Cost of gas is passed through to customers using the Quarterly Rate Adjustment Mechanism.	high
Average Ontario Gas Dist. Utility								
U.S. Gas LDCs								
AGL Resources Inc.	AGL		2,806.0	100.00%				
Atlanta Gas Light Company		GA	606.1	21.60%	Since 1998, Atlanta Gas Light has utilized a modified straight-fixed-variable rate design that enables the company to recover non-gas costs throughout the year consistent with the incurrence of these costs, essentially eliminating the need for a revenue decoupling mechanism or weather normalization adjustment.	high	As a result of the restructuring of the natural gas industry in Georgia, Atlanta Gas Light no longer procures gas for its customers and, thus, is no longer subject to the purchased gas adjustment mechanism	high
Chattanooga Gas Company		TN	124.5	4.44%	Weather normalization adjustment riders are in place. Adjustments are made at the end of each meter-reading cycle. "Normal" weather is based on the most recent 30-year period.	medium/ high	Full pass through of gas costs to customers. Chattanooga Gas (CG) operates under a performance-based-ratemaking mechanism that provides for the company to be exempt from TRA prudence audits of the company's gas procurement activities if CG's gas commodity costs during a given evaluation period do not exceed a TRA-approved benchmark by more than 1%.	high
Elizabethtown Gas		NJ	523.5	18.66%	The New Jersey Board of Public Utilities (BPU) approved a Conservation Incentive Program (CIP) that adjusts for sales declines due to conservation and weather.	high	Full pass through of gas costs to customers	high
Elkton Gas		MD	14.7	0.53%	Revenue Normalization Adjustment, adjusts for differences between actual revenues per customer and normalized revenue per customer. (full decoupling)	high	Full pass through of gas costs to customers, with annual true up	high

Regulatory Risks - Natural Gas Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Regulatory Lag: Forward Test Year, Forecasted Test Year, Adjusted Historic Test Year, Special Purpose Rate Proceedings, Other	Regulatory Lag: Overall Coverage	Financial Stability: Allowed ROE, Equity Ratio, Earnings Sharing Mechanisms, Ring Fencing	Financial Stability: Overall Coverage	Escalating Costs: O&M Tracker, Deferral Accounts	Escalating Costs: Overall Coverage
Ontario Gas LDCs										
Enbridge Inc.	ENB		16,131.3	100.00%						
Enbridge Gas Distribution Inc.		Ontario	3,011.0	18.67%	EGD's rates are set for 2008 through 2012 using the Distribution Revenue Requirement per Customer Formula. The formula is updated annually based on the average number of customers, inflation, cost pass throughs (DSM program costs, CIS/customer care costs, upstream gas costs, upstream transportation, and storage and supply mix costs), and exogenous factors beyond the control of EGD's management. The inflation adjustment is offset by an "X factor" that incorporates changes in productivity.	high	Equity ratio of 36.0% and an authorized return of 8.39%. The settlement includes an Earnings Sharing Mechanism (ESM). If EGD's actual utility ROE exceeds the Board's fomula ROE by more than 100 basis points in any one year, the resulting earnings must be shared equally with ratepayers.	medium	EGD's settlement allows for equal sharing between EGD and its ratepayers of any future increases in federal and/or provincial taxes. Revnue requirement is adjusted annually for inflation.	medium/ high
Spectra Energy Corporation	SE		5,074.0	100.00%						
Union Gas Limited		Ontario	2,130.0	41.98%	Beginning January 1, 2008, rates are set under a multi-year incentive regulation plan which allows for annual inflationary rate increases offset by a productivity factor of 1.82%. Upstream transportation and demand side management (DSM) costs continue to be passed through to customers and rates include an allowance for unexpected cost changes that are outside of management's control.	high	Equity ratio of 36% and an authorized return of 8.54%. Union Gas and its ratepayers share revenues derived from short-term storage transactions less incremental costs incurred by Union to earn those revenues. The sharing of margins earned from Union's long-term storage transactions is being phased out and by 2011, Union will retain 100% of these earnings. The incentive rate mechanism includes earnings sharing between Union Gas and its ratepayers beyond specified earnings levels.	medium	Union's settlement allows for equal sharing between Union and its ratepayers of any future increases in federal and/or provincial taxes. Revnue requirement is adjusted annually for inflation.	medium/ high
Average Ontario Gas Dist. Utility										
U.S. Gas LDCs										
AGL Resources Inc.	AGL		2,806.0	100.00%						
Atlanta Gas Light Company		GA	606.1	21.60%	By statute, electric and natural gas companies file rate cases based on projected data, and the PSC relies on average rate bases. Electric and natural gas rate case test years must be partially forecasted at the time of decision.	medium/ high	Equity ratio of 47.9% and a 10.90% ROE, Operates under a base rate freeze with no earnings restrictions until its next rate filing in 2010.	medium/ high	forecasted test year	medium
Chattanooga Gas Company		TN	124.5	4.44%	The TRA generally utilizes average rate base valuations for historical test periods. However, recognition has been accorded to an "attrition year," which incorporates known-and-reasonably-anticipated changes.	low	Equity ratio of 53% and a 10.20% ROE; Under its interruptible margin credit rider, CG equally shares with ratepayers margins resulting from transactions with non-regulated customers that utilize CG assets.	medium/ high	None noted	low
Elizabethtown Gas		NJ	523.5	18.66%	The BPU relies upon a year-end original cost rate base for a test period that is fully historical by the time a rate decision is issued. Most cases are filed utilizing partly projected data, with known-and-measurable changes permitted.	medium	Equity ratio of 52.4% with a 10.00% ROE; Purchased gas on-system sharing credit (share's margins of gas purchasing)	medium/ high	Capital Investment Recovery Tracker - Utilized to adjust Company's monthly revenues in cases wherein the actual recoveries experienced vary from the calculated revenue requirement.	high
Elkton Gas		MD	14.7	0.53%	The PSC relies on average original-cost rate bases for test periods that are fully historical at the time rate decisions are issued. Filings are usually based on partially-forecasted data, which are updated to reflect actual data during the course of the proceeding.	low	Earnings sharing for off system sales income	low/ medium	None noted	low

Regulatory Risks - Natural Gas Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Major Capital Improvements: CWIP in Rate Base, Preapproval of Construction Costs, Cost Trackers	Major Capital Improvements: Overall Coverage	Other Cost Recovery: Cost Recovery through deferral accounts and cost trackers	Other Cost Recovery: Overall Coverage
Ontario Gas LDCs								
Enbridge Inc.	ENB		16,131.3	100.00%				
Enbridge Gas Distribution Inc.		Ontario	3,011.0	18.67%	EGD's settlement stipulates that incremental revenue requirement impacts associated with annual capital expenditures related to the attachments of natural gas-fired power generation projects, that have been approved by the Board, shall be included in the Distribution Revenue Requirement per Customer Formula.	medium	Deferral and variance accounts include: purchased gas variance, transaction services, unaccounted for gas, storage and transportation, carbon dioxide offset credits, class action suit, deferred rebate, electric program earnings sharing, gas distribution access rule costs, manufactured gas plant, municipal permit fees, Ontario hearing costs, unbundled rate implementation cost, unbundled rates customer migration, average use true-up, tax rate and rule change, earnings sharing mechanism, demand side management, lost revenue adjustment mechanism, shared savings mechanism	high
Spectra Energy Corporation	SE		5,074.0	100.00%				
Union Gas Limited		Ontario	2,130.0	41.98%	Union Gas' settlement (EB-2005-0520) includes forecasted 2007 capital expenditures in rate base	high	Deferral and variance accounts include: deferred mark to market gain/losses; gas in storage; future income taxes; asset removal costs; gas deferral costs; storage and transportation deferrals; and other deferrals to recover specifically-identified costs	high
Average Ontario Gas Dist. Utility								
U.S. Gas LDCs								
AGL Resources Inc.	AGL		2,806.0	100.00%				
Atlanta Gas Light Company		GA	606.1	21.60%	Environmental Response Cost (ERC) Recovery Rider; Pipeline Replacement Program (PRP) Cost Recovery Rider	medium	Interstate Pipeline Rate Tracker; Retained Storage Tracker; ATGL has been authorized to recover clean-up costs related to former manufactured gas plant sites through an environmental response cost recovery rider (ERCRR). Costs that are recoverable under the ERCRR include investigation, testing, remediation, and/or litigation costs or other liabilities. Franchise Recovery (FR) Rider, Local Tax (LT) Adjustment Rider, Buy/Sell Rider, Emergency Commodity Sales Service (E) Surcharge Rider, Social Responsibility Cost (SRC) Rider	high
Chattanooga Gas Company		TN	124.5	4.44%	The Tennessee Regulatory Authority (TRA) allows inclusion of CWIP in rate base.	high	None noted	low
Elizabethtown Gas		NJ	523.5	18.66%	Utility Infrastructure Enhancement provides return on infrastructure investment as it is incurred annually	medium/ high	Social benefits charge for low income and environmental remediation expenses; New Jersey Clean Energy Program, Universal Service Fund ("USF") and Lifeline Components; Regulatory Asset Recovery Charge; Regional Greenhouse Gas Initiative ("RGGI"); Transitional Energy Facility Assessment ("TEFA"); Gas Cost Underrecovery Adjustment Surcharge	high
Elkton Gas		MD	14.7	0.53%	None noted	low	None noted	low

Regulatory Risks - Natural Gas Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Volume Variability and Volumetric Protection: May include: Weather Normalization, Revenue Decoupling, Straight Fixed Variable Rate Design, Tiered Rates, etc.	Overall Coverage	Fuel Cost Volatility: Purchased Gas Adjustment, Fuel Cost Pass Through, Timeliness of Recovery	Overall Coverage
Florida City Gas		FL	93.3	3.32%	None noted	low	The PGA is designed to recover purchased gas costs, and the costs of reserving and utilizing interstate pipeline capacity for the transportation of gas to customers. These charges are adjusted monthly based on a cap approved annually following a PSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs and revenues from the projections.	high
Virginia Natural Gas, Inc.		VA	N/A	N/A	Virginia State Corporation Commission approved a revenue normalization adjustment (decoupling). A Weather Normalization Adjustment (WNA) Rider is in place for Virginia Natural Gas.	high	The PGA provides for quarterly rate changes to reflect fluctuations in gas costs. There is an annual reconciliation of total billed gas charges with actual gas costs. Any deficiency or excess is deferred, and the balance is either recovered or refunded in the 12 months following the annual reconciliation	high
Piedmont Natural Gas Company, Inc.	PNY	-729K in NC -132K in SC -165K in TN	2,118.1	100.00%	NC - Piedmont has a decoupling mechanism (revenue adjustment by class by month). The original weather normalization mechanism has been replaced by the Customer Utilization Tracker (CUT) which adjusts for normal weather. (high) SC - (RSA) permits natural gas utilities, upon PSC approval, to adjust rates once per year if their earned ROE is outside a band of ±50 basis points around the previously authorized ROE. Any rate adjustment would be based on the last authorized ROE. The gas utilities must request any rate change by June 15 of each year in conjunction with their March 31 quarterly surveillance filings, and a written PSC order must be issued by October 1. (high) - TN none noted (low)	medium/ high	NC - A purchased gas adjustment (PGA) clause is utilized by natural gas utilities. Under NCUC rules: (1) gas purchasing practices are subject to an annual prudence review; (2) a local distribution company may recover expenses for additional interstate pipeline capacity and storage added prior to a general rate case, subject to annual true-up; (3) commodity and transportation rates may be adjusted within the PGA; and, (4) changes in demand and storage costs are to be allocated to all customer classes, including transportation, on a volumetric basis. (high) - SC allows gas costs to be passed on to customers. The companies' rates are based on the projected cost of gas, with differences between actual and projected costs deferred and reviewed by the PSC. (medium/high) - TN For the state's gas utilities, commodity costs are reflected through an automatic adjustment clause, and incentive mechanisms are in place related to gas procurement, capacity release, and off-system sales. (high)	high
South Jersey Industries, Inc.	SJI		963.3	100.00%				
South Jersey Gas Company		NJ	568.0	58.97%	The New Jersey Board of Public Utilities (BPU) approved a Conservation Incentive Program (CIP) that adjusts for sales declines due to conservation and weather.	high	Full pass through of gas costs to customers	high
Sempra Energy	SRE		11,456.0	100.00%				
Mobile Gas Service Corporation		AL	108.5	0.95%	Rate Stabilization and Equalization Factor allows incorporation of projected data to set rates. Annual rate increases under RSE are capped at 4% of the previous year's revenue, and any indicated rate changes, based on a forecasted test year are to be implemented only once per year on Dec. 1. Rate decreases, based on historical results, may be implemented every three months. includes weather normalization.	medium/ high	Automatic gas cost recovery mechanisms	medium/ high
San Diego Gas & Electric Co.		CA	3,306.9	28.87%	California's electric and gas utilities operate under revenue adjustment (decoupling) mechanisms that modify rates annually to reflect changes in KWH sales and throughput from levels utilized to establish the revenue requirement.	high	As of April 1, 2009, SDG&E and SCG operate under a combined portfolio and are subject to a Gas Cost Incentive Mechanism that provides for gas costs above or below a tolerance band around a benchmark level to be shared by ratepayers and stockholders.	medium/ high

Regulatory Risks - Natural Gas Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Regulatory Lag: Forward Test Year, Forecasted Test Year, Adjusted Historic Test Year, Special Purpose Rate Proceedings, Other	Regulatory Lag: Overall Coverage	Financial Stability: Allowed ROE, Equity Ratio, Earnings Sharing Mechanisms, Ring Fencing	Financial Stability: Overall Coverage	Escalating Costs: O&M Tracker, Deferral Accounts	Escalating Costs: Overall Coverage
Florida City Gas		FL	93.3	3.32%	In permanent base rate case decisions, the PSC generally has utilized test periods that are fully or partially forecasted at the time the rate decisions are issued.	medium	Equity ratio of 36.8% with a 11.25% ROE	medium	forecasted test year	medium
Virginia Natural Gas, Inc.		VA	N/A	N/A	The SCC has generally relied upon a year-end original cost rate base for a historical test period, with materials and supplies valued on a 13-month average basis. The Commission has also allowed adjustments to rate base to reflect known-and-measurable pro forma changes.	low	Equity ratio is 44.8% with an authorized ROE of 10.9%. In July 2006, the SCC adopted a settlement providing for VNG to operate under a performance-based ratemaking (PBR) plan that includes a five-year rate freeze with no earnings restrictions	medium	PBR plan	medium
Piedmont Natural Gas Company, Inc.	PNY	-729K in NC -132K in SC -165K in TN	2,118.1	100.00%	NC - State law requires the NCUC to utilize a year-end original-cost rate base for a historic test period, and to consider changes that are known and quantifiable prior to the close of hearings. SC - (RSA) permits natural gas utilities, upon PSC approval, to adjust rates once per year if their earned ROE is outside a band of ±50 basis points around the previously authorized ROE. (high) - TN - none noted (low)	low/ medium	In North Carolina, the equity ratio is 51% and an authorized ROE of 10.60% (medium). In South Carolina, the equity ratio is 54.19% and the authorized ROE is 12.5%. SC - (RSA) permits natural gas utilities, upon PSC approval, to adjust rates once per year if their earned ROE is outside a band of ±50 basis points around the previously authorized ROE. (high) TN - ROEs and equity ratios in mid range (medium)	medium	NC - CUT tracker recovers lost margins for sales for any reasons (med/high); SC - essentially the same, (RSA) permits natural gas utilities, upon PSC approval, to adjust rates once per year if their earned ROE is outside a band of ±50 basis points around the previously authorized ROE. (high) TN - none noted (low)	medium/ high
South Jersey Industries, Inc.	SJI		963.3	100.00%						
South Jersey Gas Company		NJ	568.0	58.97%	The BPU relies upon a year-end original cost rate base for a test period that is fully historical by the time a rate decision is issued. Most cases are filed utilizing partly projected data, with known-and-measurable changes permitted.	medium	Equity ratio of 46% with a 10.00% ROE; South Jersey Gas may retain 100% of the first $7.8 million of pre-tax margins associated with off system sales, interruptible sales, and interruptible transportation activities. Margins beyond this level are allocated 85% to ratepayers and 15% to the company.	medium/ high	Capital Investment Recovery Tracker - Utilized to adjust Company's monthly revenues in cases wherein the actual recoveries experienced vary from the calculated revenue requirement.	high
Sempra Energy	SRE		11,456.0	100.00%						
Mobile Gas Service Corporation		AL	108.5	0.95%	Rate Stabilization and Equalization Factor allows incorporation of projected data to set rates. Annual rate increases under RSE are capped at 4% of the previous year's revenue	medium/ high	Equity ratio of 46.99% with a 13.6% ROE, RSE mechanism - the allowed ROE range for MG's plan is 13.35%-to-13.85%, with an adjusting point of 13.6%; the cost-control incentive mechanism utilizes the change in the per-customer consumer price index, plus or minus 1.5 percentage points as its deadband; and, the equity percentage upon which the company can earn a return is capped at 60%.	high	RSE mechanism includes a cost-control incentive plan, under which recovery of changes in O&M expenses are subject to caps based on changes in the Consumer Price Index (CPI).	medium/ high
San Diego Gas & Electric Co.		CA	3,306.9	28.87%	In California general rate cases, the PUC relies on a weighted-average original-cost rate base for a test period that is fully forecasted at the time of filing.	high	Equity ratio of 49% with an authorized ROE of 10.7%. Authorized ROEs are annually reviewed and reset if changes in utility bond yields exceed certain levels. The 2008 ROE determinations were carried over for 2009. On August 1, 2008, the PUC adopted a multi-year (2008 through 2011) settlement establishing a performance based ratemaking (PBR) framework that provides for specific rate increases in each year, and does not contain any earnings caps or sharing provisions. Energy efficiency incentive mechanism for generated energy savings, includes earnings sharing component. As of April 1, 2009, SDG&E and SCG operate under a combined portfolio and are subject to a Gas Cost Incentive Mechanism that provides for gas costs above or below a tolerance band around a benchmark level to be shared by ratepayers and stockholders.	medium/ high	specified annual increase in rates each year as part of PBR plan.	medium/ high

Regulatory Risks - Natural Gas Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Major Capital Improvements: CWIP in Rate Base, Preapproval of Construction Costs, Cost Trackers	Major Capital Improvements: Overall Coverage	Other Cost Recovery: Cost Recovery through deferral accounts and cost trackers	Other Cost Recovery: Overall Coverage
Florida City Gas		FL	93.3	3.32%	None noted	low	Energy Conservation Cost Recovery Adjustment ("ECCR"), Competitive Rate Adjustment ("CRA"), Load Enhancement Discount ("LED"), Alternate Fuel Discount ("AFD"), Storm damage restoration adjustment, Certain fees and taxes, such as franchise fees and gross receipts taxes, are recovered through a line item on customer bills, with the charge adjusted based on customer usage.	high
Virginia Natural Gas, Inc.		VA	N/A	N/A	.B. 145, enacted in 2008, authorizes a natural gas utility that places a "strategic" natural gas facility into service on or after July 1, 2008, to recover the entire prudently incurred costs of the facility from the time the asset is placed into service until SCC establishes new rates. Recovery is subject to a SCC determination that the costs were prudently incurred.	medium	None noted	low
Piedmont Natural Gas Company, Inc.	PNY	-729K in NC -132K in SC -165K in TN	2,118.1	100.00%	Senate Bill 3, which was enacted in August 2007, appears to facilitate the North Carolina Utility Commission's ability to allow a cash return on CWIP. "to the extent...such inclusion is in the public interest and necessary to the financial stability of the utility in question" (med/high). SC also allows CWIP on construction though generally pertains to generation projects. (med/high). TN - none noted (low)	medium/ high	NC, SC & TN - None noted (low)	low
South Jersey Industries, Inc.	SJI		963.3	100.00%				
South Jersey Gas Company		NJ	568.0	58.97%	CWIP on a case by case basis, usually for a showing of financial distress	medium/ high	Remediation Adjustment Clause - Based on remediation costs and third party expenses/claims in the preceding Remediation Year.	low/ medium
Sempra Energy	SRE		11,456.0	100.00%				
Mobile Gas Service Corporation		AL	108.5	0.95%	None noted	low	None noted	low
San Diego Gas & Electric Co.		CA	3,306.9	28.87%	None noted	low	LNG Tracking Account and Global Settlement Tracking Account. Various balancing accounts focusing on renewable and advanced energy initiatives, and current business operations, amongst others.	medium

Regulatory Risks - Natural Gas Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Volume Variability and Volumetric Protection: May include: Weather Normalization, Revenue Decoupling, Straight Fixed Variable Rate Design, Tiered Rates, etc.	Overall Coverage	Fuel Cost Volatility: Purchased Gas Adjustment, Fuel Cost Pass Through, Timeliness of Recovery	Overall Coverage
Southern California Gas Company		CA	4,759.4	41.55%	California's electric and gas utilities operate under revenue adjustment (decoupling) mechanisms that modify rates annually to reflect changes in KWH sales and throughput from levels utilized to establish the revenue requirement.	high	As of April 1, 2009, SDG&E and SCG operate under a combined portfolio and are subject to a Gas Cost Incentive Mechanism that provides for gas costs above or below a tolerance band around a benchmark level to be shared by ratepayers and stockholders.	medium/ high
Southwest Gas Corporation	SWX	-179K in CA -982K in AZ -658K in NV	-179K -982K -658K	100.00%	California's electric and gas utilities operate under revenue adjustment (decoupling) mechanisms that modify rates annually to reflect changes in KWH sales and throughput from levels utilized to establish the revenue requirement (high). Arizona employs a fair value rate base.(medium) Nevada has been invited by the Commission to submit a decoupling proprosal (medium/ high) (dcoupling still pending).	medium/ high	In Arizona PGA filings, Southwest adjusts rates monthly for changes in purchased gas costs, within pre-established limits measured on a twelve-month rolling average. A prudence review of gas costs is conducted in conjunction with general rate cases (medium). In California, a monthly gas cost adjustment based on forecasted monthly prices is utilized high). In Nevada, quarterly gas cost charges, that are based on a twelve-month rolling average, are utilized. Annual deferred energy account adjustments are subject to a prudence review and audit of the natural gas costs incurred.(medium)	medium/ high
Vectren Corporation	VVC		2,524.2	100.00%				
Indiana Gas Company, Inc.		IN	865.0	34.27%	Vectren has a decoupling mechanism adjusted for growth in customers. IG and SIGECO utilize a normal temperature adjustment (NTA) mechanism to eliminate the impact of deviations in normal temperatures on gas distribution revenues.	high	With regard to gas purchases, utilities recover the difference between actual and estimated gas costs through the gas cost adjustment (GCA) clause. SIGECO and Indiana Gas (IG) are permitted to apply on a monthly basis for GCA changes. By law, the URC may not approve a revised GCA if it will result in a utility earning an NOI in excess of that authorized in the utility's last base rate case.	medium
Southern Indiana Gas and Electric Company, Inc.		IN	683.9	27.09%	Vectren has a decoupling mechanism adjusted for growth in customers. IG and SIGECO utilize a normal temperature adjustment (NTA) mechanism to eliminate the impact of deviations in normal temperatures on gas distribution revenues.	high	With regard to gas purchases, utilities recover the difference between actual and estimated gas costs through the gas cost adjustment (GCA) clause. SIGECO and Indiana Gas (IG) are permitted to apply on a monthly basis for GCA changes. By law, the URC may not approve a revised GCA if it will result in a utility earning an NOI in excess of that authorized in the utility's last base rate case.	medium
Vectren Energy Delivery of Ohio, Inc.		OH	408.1	16.17%	Vectren Energy Delivery of Ohio (VEDO) operates under straight fixed variable rate design.	high	gas cost recovery clause (GCR), which provides for quarterly adjustments, with an annual review and hearing. The GCR includes a mechanism to revise charges in a subsequent three-month period for any under- or over-recoveries related to the collection of an earlier period. With PUC approval, a local distribution company can make monthly changes to its GCR.	high

Regulatory Risks - Natural Gas Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Regulatory Lag: Forward Test Year, Forecasted Test Year, Adjusted Historic Test Year, Special Purpose Rate Proceedings, Other	Regulatory Lag: Overall Coverage	Financial Stability: Allowed ROE, Equity Ratio, Earnings Sharing Mechanisms, Ring Fencing	Financial Stability: Overall Coverage	Escalating Costs: O&M Tracker, Deferral Accounts	Escalating Costs: Overall Coverage
Southern California Gas Company		CA	4,759.4	41.55%	In California general rate cases, the PUC relies on a weighted-average original-cost rate base for a test period that is fully forecasted at the time of filing.	high	Equity ratio of 48% with an authorized ROE of 10.82%. Authorized ROEs are annually reviewed and reset if changes in utility bond yields exceed certain levels. The 2008 ROE determinations were carried over for 2009. On August 1, 2008, the PUC adopted a multi-year (2008 through 2011) settlement establishing a performance based ratemaking (PBR) framework that provides for specific rate increases in each year, and does not contain any earnings caps or sharing provisions. Energy efficiency incentive mechanism for generated energy savings, includes earnings sharing component. As of April 1, 2009, SDG&E and SCG operate under a combined portfolio and are subject to a Gas Cost Incentive Mechanism that provides for gas costs above or below a tolerance band around a benchmark level to be shared by ratepayers and stockholders.	medium/ high	specified annual increase in rates each year as part of PBR plan.	medium/ high
Southwest Gas Corporation	SWX	-179K in CA -982K in AZ -658K in NV	-179K -982K -658K	100.00%	In Arizona rate cases, the utilities also provide an historical rate base and the traditionally calculated rate of return, the product of which is equal to the product of the fair-value rate base and the authorized fair-value return.(high) In California general rate cases, the PUC relies on a weighted-average original-cost rate base for a test period that is fully forecasted at the time of filing. (high) The Nevada PUC relies upon year-end rate base valuations for test periods that generally conclude less than one year prior to the date of decision. Recently enacted legislation, Assembly Bill 103, permits electric and gas utilities to utilize a "hybrid" test year methodology consisting of historical test years with updates for known-and-measurable adjustments up to 210 days beyond the filing date. (medium)	medium/ high	In Arizona, equity ratio is 43.44% with an approved ROE of 10%. In Nevada, the equity ratio is 40% while the approved ROE is 10.5%. In California, equity ratio is 47% while approved ROE is 10.5% -performance based ratemaking (PBR) frameworks that provide for specific rate increases in each year, and do not contain any earnings caps or sharing provisions. Energy efficiency incentive mechanism for generated energy savings, includes earnings sharing component.	medium	specified annual increase in rates each year as part of PBR plan.	low/ medium
Vectren Corporation	VVC		2,524.2	100.00%						
Indiana Gas Company, Inc.		IN	865.0	34.27%	Indiana is statutorily a fair-value state. URC has, in most instances, calculated its fair-value rate base and return findings after having determined a return on original-cost rate base on the basis of an historical test period and a test year-end rate base, with adjustments for known-and-measurable changes expected to occur within one year after the end of the test period.	medium/ high	Equity ratio of 48.99% with a 10.20% ROE	medium	fair value rate base	high
Southern Indiana Gas and Electric Company, Inc.		IN	683.9	27.09%	Indiana is statutorily a fair-value state. URC has, in most instances, calculated its fair-value rate base and return findings after having determined a return on original-cost rate base on the basis of an historical test period and a test year-end rate base, with adjustments for known-and-measurable changes expected to occur within one year after the end of the test period.	medium/ high	Equity ratio of 47.05% with a 10.15% ROE for its gas operations	medium	fair value rate base	high
Vectren Energy Delivery of Ohio, Inc.		OH	408.1	16.17%	Ohio law requires utilization of an original cost rate base valued as of a date certain, which can be no later than the date the rate case is filed. Statutes require that the test year conclude within nine months after the filing of a rate increase application.	low/ medium	8.89% overall return, but was silent with respect to ROE.	medium	None noted	low

Regulatory Risks - Natural Gas Utilities

Regulatory Mechanisms	Ticker	State/ Province	Revenue	% of Total Revenue	Major Capital Improvements: CWIP in Rate Base, Preapproval of Construction Costs, Cost Trackers	Major Capital Improvements: Overall Coverage	Other Cost Recovery: Cost Recovery through deferral accounts and cost trackers	Other Cost Recovery: Overall Coverage
Southern California Gas Company		CA	4,759.4	41.55%	None noted	low	Noncore fixed cost tracking account, Transition cost surcharge tracking account.	low/ medium
Southwest Gas Corporation	SWX	-179K in CA -982K in AZ -658K in NV	-179K -982K -658K	100.00%	None noted - AZ (low); NV (low); CA (low)	low	CA: Interstate Transportation Cost Adjustment; Fixed Cost Adjustment Mechanism; Public Utilities Commission Reimbursement Fee	low/ medium
Vectren Corporation	VVC		2,524.2	100.00%				
Indiana Gas Company, Inc.		IN	865.0	34.27%	Indiana Gas may accrue allowance for funds used during construction (AFUDC) and defer the depreciation expense (up to a $20 million annual cap) between the in-service date and the date certain distribution system projects are reflected in rate base, according to a pre-determined schedule.	medium/ high	Indiana Gas utilizes energy efficiency riders (EERs) to recover the costs associated with its natural gas energy efficiency programs. Also has Pipeline Safety Adjustment for incremental O&M expenses related to complying with Federal safety mandates. IG to recover incremental changes (representing an increase of approximately $10.6 million) in its unaccounted-for gas costs up to a maximum percentage of 0.8% of gas volumes, and the gas-cost component of bad debts at a fixed bad debt ratio of 0.9% through its GCA filings	medium/ high
Southern Indiana Gas and Electric Company, Inc.		IN	683.9	27.09%	SIGECO may accrue allowance for funds used during construction (AFUDC) and defer the depreciation expense between the in-service date and the date certain distribution system projects are reflected in rate base, according to a pre-determined schedule.	medium/ high	SIGECO recovers the costs associated with an environmental compliance plan through a surcharge mechanism. Also has Pipeline Safety Adjustment for incremental O&M expenses related to complying with Federal safety mandates. SIGECO has tracker for unaccounted-for gas costs (up to a maximum percentage of 1.2% of gas volumes) through its GCA filings; SIGECO to continue to recover incremental pipeline safety improvement costs, up to $1 million annually, through its PSA mechanism -- incremental amounts above the $1 million annual cap may be deferred without carrying charges for future recovery; and, SIGECO to utilize the SRC of its EER, whereby 100% of margins lost as a result of gas conservation are to be recovered.	medium/ high
Vectren Energy Delivery of Ohio, Inc.		OH	408.1	16.17%	State law provides for allowance of construction work in progress (CWIP) in rate base at the PUC's discretion if a project is 75% complete. However, the proportion of non-pollution-control CWIP that the PUC may include in rate base is limited to 10% of rate base excluding CWIP.	medium/ high	PUC established a conservation program and a sales reconciliation rider; Distribution Replacement Rider - Enables the Company to recover incremental costs incurred under a multi-year program for the accelerated replacement and retirement cost of mains and service lines.	medium/ high

Financial Profile - Electric Utilities

	Ticker	State/ Province	Ownership	[1] Revenue ($M)	[2] % of Total Revenue	[3] Credit Rating	[4] Approved Equity Ratio	[5] Authorized Return	[6] Embedded Debt Cost	[7] Actual Debt /Capital Ratio	[8] Actual Debt /Equity Ratio	[9] EBIT Interest Coverage Ratio	[10] FFO/ Interest Coverage	[11] FFO/ Debt
Ontario Electric LDCs														
Enersource Hydro Mississauga Inc.		Ontario	Municipal	670.7	100.00%	A	40.00%	8.57%	6.66%	56.25%	1.29	2.36	3.60	24.00%
Horizon Utilities Corporation		Ontario	Municipal	98.1	100.00%	A+	40.00%	8.57%	7.00%	39.80%	0.66	3.23	5.05	41.46%
Hydro One Networks Inc. (Distribution)		Ontario	Provincial	2,956.0	100.00%	A+	40.00%	8.57%	5.43%	58.41%	1.40	2.50	4.21	21.86%
Hydro Ottawa Limited		Ontario	Municipal	692.9	100.00%	A	40.00%	8.57%	5.27%	55.77%	0.56	3.54	5.36	26.68%
PowerStream Inc.		Ontario	Municipal	606.2	100.00%	N/A	40.00%	8.01%	5.67%	58.65%	1.42	2.58	4.08	21.02%
Toronto Hydro Electric System		Ontario	Municipal	2,349.5	100.00%	A	40.00%	8.01%	6.01%	59.81%	1.49	2.05	4.11	25.71%
Veridian Connections Inc.		Ontario	Municipal	228.8	100.00%	A	40.00%	9.00%	7.58%	49.72%	0.99	2.03	4.41	33.97%
Average Ontario Electric Dist. Utility			Govnmt. Owned	1,086.0			40.00%	8.47%	6.23%	54.06%	1.12	2.61	4.40	27.81%
U.S. Electric LDCs														
CH Energy Group, Inc.	CHG		Investor-Owned	1,338.1	100.00%	N/A	N/A	N/A	4.90%	47.27%	0.90	3.25	4.36	24.14%
Central Hudson Gas & Electric Corp.		NY		798.0	59.64%	A	47.00%	10.00%	4.90%	53.81%	1.17	1.88	3.64	20.16%
Consolidated Edison, Inc.	ED		Investor-Owned	13,941.0	100.00%	A-	N/A	N/A	5.72%	51.01%	1.04	3.69	5.39	29.04%
Consolidated Edison Company of New York, Inc.		NY		10,573.1	75.84%	A-	48.00%	10.00%	5.77%	50.05%	1.00	2.59	5.00	26.65%
Orange & Rockland Utilities, Inc.		NJ, NY, PA		777.6	5.58%	A-	48.00%	9.40%	N/A	46.68%	0.88	2.16	4.53	30.23%
Pike County Light & Power Company		PA		7.2	0.05%	N/A	N/A	N/A	N/A	42.29%	0.73	0.88	2.56	20.22%
Rockland Electric Company		NJ		237.7	1.71%	A-	46.51%	9.75%	N/A	0.00%	0.00	N/A	N/A	N/A
DPL Inc.	DPL		Investor-Owned	1,604.2	100.00%	A-	N/A	N/A	6.09%	61.40%	1.59	4.83	5.80	33.89%
Dayton Power and Light Company		OH		1,656.6	103.27%	A-	49.57%	13.00%	5.39%	37.44%	0.60	7.44	11.51	56.20%
Duke Energy Corporation	DUK		Investor-Owned	13,397.0	100.00%	A-	N/A	N/A	5.95%	40.76%	0.69	3.63	5.74	29.48%
Duke Energy Carolinas, LLC		NC, SC		5,881.8	43.90%	A-	51.50%	11.63%	N/A	49.87%	0.99	2.90	6.28	28.59%
Duke Energy Indiana, Inc.		IN		2,480.7	18.52%	A-	44.44%	10.50%	N/A	52.27%	1.09	2.68	5.84	23.89%
Duke Energy Kentucky, Inc.		KY		500.1	3.73%	A-	N/A	N/A	N/A	45.48%	0.83	2.99	5.86	31.51%
Duke Energy Ohio, Inc.		OH		3,167.4	23.64%	A-	51.59%	10.63%	N/A	21.43%	0.27	4.07	10.82	42.94%
FPL Group, Inc.	FPL		Investor-Owned	16,487.0	100.00%	A	N/A	N/A	5.83%	59.39%	1.46	3.59	5.49	26.11%
Florida Power & Light Company		FL		11,646.8	70.64%	A	N/A	N/A	6.19%	42.59%	0.74	3.36	6.75	36.90%
MGE Energy Group, Inc.	MGEE		Investor-Owned	604.0	100.00%	N/A	N/A	N/A	6.03%	45.36%	0.83	6.87	8.19	28.88%
Madison Gas and Electric Company		WI		631.5	104.55%	AA-	57.36%	10.80%	6.03%	37.09%	0.59	3.33	5.96	31.61%
NSTAR	NST		Investor-Owned	3,357.6	100.00%	A+	N/A	N/A	6.62%	62.85%	1.69	3.56	5.16	25.90%
NSTAR Electric Company		MA		2,902.4	86.44%	A+	N/A	N/A	5.49%	49.79%	0.99	3.49	5.12	22.58%
Southern Company	SO		Investor-Owned	17,209.0	100.00%	A	N/A	N/A	5.59%	56.80%	1.31	4.14	5.00	23.56%
Alabama Power Company		AL		6,087.4	35.37%	A	N/A	N/A	5.39%	51.49%	1.06	3.21	5.70	27.02%
Georgia Power Company		GA		8,546.4	49.66%	A	N/A	N/A	5.34%	51.46%	1.06	3.41	6.06	27.29%
Gulf Power Company		FL		1,387.4	8.06%	A	41.02%	12.00%	5.42%	52.02%	1.08	3.14	5.94	25.64%
Mississippi Power Company		MS		1,264.7	7.35%	A	53.68%	12.88%	5.51%	39.30%	0.65	5.75	11.29	46.84%
Average U.S. Electric Dist. Proxy Group			Investor-Owned				48.97%	10.96%	5.54%	42.53%	0.81	3.33	6.43	31.14%

Sources:

[1] Canada: 2008 Annual Reports (data at operating company level except for Enersource Hydro Mississauga & PowerStream which are at the corporate level)
U.S. holding companies: 2008 10-Ks, data downloaded from SNL Financial
U.S. operating companies: 2008 FERC Form 1; data downloaded from SNL Financial
[2] Operating company revenue / holding company revenue
[3] Canada: 2008 Annual Reports
U.S.: S&P; data downloaded from SNL Financial
[4] Canada: 2008 Annual Reports
U.S.: Regulatory Research Associates; equals average of all service territories for each operating company
[5] Canada: 2008 Annual Reports
U.S.: Regulatory Research Associates; equals average of all service territories for each operating company
[6] Canada: 2008 Annual Reports; equals interest expense / total debt
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial; equals interest expense / total debt
U.S. operating companies: 2008 FERC Form 1, pages 112 and 117; data downloaded from SNL Financial; equals net interest charges / [total long-term debt + notes payable + notes payable to associated companies]
[7] Canada: 2008 Annual Reports; equals total debt / [total equity + total debt]
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial; equals total debt / [total equity + total debt]
U.S. operating companies: 2008 FERC Form 1, page 112; data downloaded from SNL Financial; equals [total long-term debt + notes payable + notes payable to associated companies] / [total proprietary capital + total long-term debt + notes payable + notes payable to associated companies]
[8] Canada: 2008 Annual Reports; equals total debt / total equity
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial; equals total debt / total equity
U.S. operating companies: 2008 FERC Form 1, page 112; data downloaded from SNL Financial; equals [total long-term debt + notes payable + notes payable to associated companies] / total proprietary capital
[9] Canada: 2008 Annual Reports; equals earnings before interest and taxes / interest expense
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial; equals earnings before interest and taxes / interest expense
U.S. operating companies: 2008 FERC Form 1, page 117; data downloaded from SNL Financial; equals net utility operating income / net interest charges
[10] Canada: 2008 Annual Reports; equals [net income + interest expense + depreciation and amortization expense + deferred income tax expense] / interest expense
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial; equals [net income + interest expense + depreciation and amortization expense + deferred income tax expense] / interest expense
U.S. operating companies: 2008 FERC Form 1, pages 114 and 117; data downloaded from SNL Financial; equals [net income + net interest charges + depreciation expense + depreciation expense for asset retirement costs + amortization and depletion of utility plant + amortization of utility plant acquisition adjustment + amortization of property losses, unrecovered plant and regulatory study costs + amortization of conversion expenses + provision for deferred income taxes − provision for deferred income taxes (credit)] / net interest charges
[11] Canada: 2008 Annual Reports; equals [net income + interest expense + depreciation and amortization expense + deferred income tax expense] / total debt
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial; equals [net income + interest expense + depreciation and amortization expense + deferred income tax expense] / total debt
U.S. operating companies: 2008 FERC Form 1, pages 112, 114 and 117; data downloaded from SNL Financial; equals [net income + net interest charges + depreciation expense + depreciation expense for asset retirement costs + amortization and depletion of utility plant + amortization of utility plant acquisition adjustment + amortization of property losses, unrecovered plant and regulatory study costs + amortization of conversion expenses + provision for deferred income taxes − provision for deferred income taxes (credit)] /[total long-term debt + notes payable + notes payable to associated companies]

Financial Profile - Natural Gas Utilities

				[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
	Ticker	**State/ Province**	**Ownership**	**Revenue ($M)**	**% of Total Revenue**	**Credit Rating**	**Approved Equity Ratio**	**Authorized Return**	**Embedded Debt Cost**	**Actual Debt /Capital Ratio**	**Actual Debt /Equity Ratio**	**EBIT Interest Coverage Ratio**	**FFO/ Interest Coverage**	**FFO/ Debt**
Ontario Gas LDCs														
Enbridge Inc.	ENB		Investor-Owned	16,131.3	100.00%	A-	N/A	N/A	4.65%	66.64%	2.00	2.48	4.59	19.14%
Enbridge Gas Distribution Inc.		Ontario		3,011.0	18.67%	A-	36.00%	8.39%	6.60%	62.24%	1.65	2.19	3.32	20.90%
Spectra Energy Corporation	SE		Investor-Owned	5,074.0	100.00%	BBB	N/A	N/A	6.54%	61.71%	1.61	2.33	3.67	23.23%
Union Gas Limited		Ontario		2,130.0	41.98%	BBB+	36.00%	8.54%	6.24%	63.99%	1.78	2.47	3.47	20.12%
Average Ontario Gas Dist. Utility							36.00%	8.47%	6.42%	63.11%	1.71	2.33	3.40	20.51%
U.S. Gas LDCs														
AGL Resources Inc.	AGL		Investor-Owned	2,806.0	100.00%	A-	N/A	N/A	5.33%	60.14%	1.51	4.21	5.16	23.34%
Atlanta Gas Light Company		GA		606.1	21.6%	A-	47.90%	10.90%	6.72%	51.31%	1.05	2.44	4.76	29.93%
Chattanooga Gas Company		TN		124.5	4.4%	N/A	44.80%	10.20%	1.75%	49.15%	0.97	12.27	30.28	26.43%
Elizabethtown Gas		NJ		523.5	18.7%	N/A	53.00%	10.00%	4.77%	46.40%	0.87	2.31	4.81	22.58%
Elkton Gas		MD		14.7	0.5%	N/A	N/A	N/A	7.14%	49.10%	0.96	1.60	2.39	19.67%
Florida City Gas		FL		93.3	3.3%	A-	36.80%	11.25%	7.06%	49.27%	0.97	1.96	5.26	37.32%
Virginia Natural Gas, Inc.		VA		N/A	N/A	A-	52.40%	10.90%	N/A	N/A	N/A	N/A	N/A	N/A
Piedmont Natural Gas Company, Inc.	PNY	NC, SC, TN	Investor-Owned	2,118.1	100.00%	A	52.60%	11.55%	6.72%	58.11%	1.39	4.16	4.89	23.54%
South Jersey Industries, Inc.	SJI		Investor-Owned	963.3	100.00%	N/A	N/A	N/A	7.17%	52.54%	1.11	6.03	6.03	27.15%
South Jersey Gas Company		NJ		568.0	58.97%	BBB+	46.00%	10.00%	5.96%	50.47%	1.02	3.11	5.63	25.75%
Sempra Energy	SRE		Investor-Owned	11,456.0	100.00%	BBB+	N/A	N/A	6.79%	48.34%	0.94	7.17	9.42	31.94%
Mobile Gas Service Corporation		AL		108.5	0.95%	N/A	46.99%	13.60%	8.99%	51.54%	1.06	3.07	6.43	36.63%
San Diego Gas & Electric Co.		CA		3,306.9	28.87%	A	49.00%	10.70%	5.93%	41.87%	0.72	3.51	7.32	46.19%
Southern California Gas Company		CA		4,759.4	41.55%	A	48.00%	10.82%	5.00%	47.72%	0.91	4.72	10.73	49.31%
Southwest Gas Corporation	SWX	AZ, CA, NV	Investor-Owned	2,131.3	100.00%	BBB	43.48%	10.33%	7.42%	56.51%	1.30	2.11	4.12	28.31%
Vectren Corporation	VVC		Investor-Owned	2,524.2	100.0%	A-	N/A	N/A	6.41%	57.75%	1.37	3.12	5.11	27.06%
Indiana Gas Company, Inc.		IN		865.0	34.3%	A-	48.99%	10.20%	6.44%	40.38%	1.09	2.25	4.86	27.62%
Southern Indiana Gas and Electric Company, Inc.		IN		683.9	27.1%	A-	47.05%	10.15%	6.90%	52.46%	1.10	2.62	4.96	26.20%
Vectren Energy Delivery of Ohio, Inc.		OH		408.1	16.2%	A-	N/A	N/A	N/A	0.00%	0.00	52.95	106.75	N/A
Average U.S. Gas Dist. Proxy Group							47.46%	10.82%	6.22%	46.02%	0.96	7.08	7.42	30.73%

Sources:

[1] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks, data downloaded from SNL Financial
U.S. operating companies: 2008 Gas LDC Filings; data downloaded from SNL Financial

[2] Operating company revenue / holding company revenue

[3] Canada: 2008 Annual Reports
U.S.: S&P; data downloaded from SNL Financial

[4] Canada: 2008 Annual Reports
U.S.: Regulatory Research Associates; equals average of all service territories for each operating company

[5] Canada: 2008 Annual Reports
U.S.: Regulatory Research Associates; equals average of all service territories for each operating company

[6] Canada: 2008 Annual Reports; equals interest expense / total debt
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial; equals interest expense / total debt
U.S. operating companies: 2008 Gas LDC Filings; data downloaded from SNL Financial; equals net interest charges / [total long-term debt + notes payable + notes payable to associated companies]

[7] Canada: 2008 Annual Reports; equals total debt / [total equity + total debt]
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial; equals total debt / [total equity + total debt]
U.S. operating companies: 2008 Gas LDC Filings; data downloaded from SNL Financial; equals [total long-term debt + notes payable + notes payable to associated companies] / [total proprietary capital + total long-term debt + notes payable + notes payable to associated companies]

[8] Canada: 2008 Annual Reports; equals total debt / total equity
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial; equals total debt / total equity
U.S. operating companies: 2008 Gas LDC Filings; data downloaded from SNL Financial; equals [total long-term debt + notes payable + notes payable to associated companies] / total proprietary capital

[9] Canada: 2008 Annual Reports; equals earnings before interest and taxes / interest expense
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial; equals earnings before interest and taxes / interest expense
U.S. operating companies: 2008 Gas LDC Filings; data downloaded from SNL Financial; equals net utility operating income / net interest charges

[10] Canada: 2008 Annual Reports; equals [net income + interest expense + depreciation and amortization expense + deferred income tax expense] / interest expense
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial; equals [net income + interest expense + depreciation and amortization expense + deferred income tax expense] / interest expense
U.S. operating companies: 2008 Gas LDC Filings; data downloaded from SNL Financial; equals [net income + net interest charges + depreciation expense + depreciation expense for asset retirement costs + amortization and depletion of utility plant +amortization of utility plant acquisition adjustment + amortization of property losses, unrecovered plant and regulatory study costs + amortization of conversion expenses + provision for deferred income taxes − provision for deferred income taxes (credit)] / net interest charges

[11] Canada: 2008 Annual Reports; equals [net income + interest expense + depreciation and amortization expense + deferred income tax expense] / total debt
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial; equals [net income + interest expense + depreciation and amortization expense + deferred income tax expense] / total debt
U.S. operating companies: 2008 Gas LDC Filings; data downloaded from SNL Financial; equals [net income + net interest charges + depreciation expense + depreciation expense for asset retirement costs + amortization and depletion of utility plant + amortization of utility plant acquisition adjustment + amortization of property losses, unrecovered plant and regulatory study costs + amortization of conversion expenses + provision for deferred income taxes − provision for deferred income taxes (credit)] / [total long-term debt + notes payable + notes payable to associated companies]

Business Profile - Electric Utilities

			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
							Customer Mix									
	Ticker	State/ Province	Revenue	% of Total Revenue	Residential	%	Commercial	%	Industrial	%	Total Customers	Industrial Revenue / Total Revenue	Net Plant ($M)	Generation Supply Requirements	Restructured Market	% Service Territory Growth
Ontario Electric LDCs																
Enersource Hydro Mississauga Inc.		Ontario	670.7	100.00%	164,329	89%	20,985	11%	10	0%	185,324	N/A	419.2	N/A	Yes	*see note [19]*
Horizon Utilities Corporation		Ontario	98.1	100.00%	211,942	91%	20,140	9%	12	0%	234,000	2.60%	307.7	N/A	Yes	*see note [22]*
Hydro One Networks Inc. (Distribution)		Ontario	2,956.0	100.00%	1,300,000	51%	N/A	34%	47	6%	1,300,000	6.00%	4,336.0	N/A	Yes	N/A
Hydro Ottawa Limited		Ontario	692.9	100.00%	264,080	91%	26,428	9%	11	0%	291,000	0.00%	494.7	N/A	Yes	*see note [27]*
PowerStream Inc.		Ontario	606.2	100.00%	211,116	89%	26,832	11%	1	0%	314,044	N/A	445.7	N/A	Yes	*see note [30]*
Toronto Hydro Electric System		Ontario	2,349.5	100.00%	611,808	89%	78,440	11%	49	0%	684,000	8.60%	1,786.9	N/A	Yes	N/A
Veridian Connections Inc.		Ontario	228.8	100.00%	110,861	N/A	N/A	N/A	N/A	N/A	110,861	N/A	134.4	N/A	Yes	1.50%
Average Ontario Electric Dist. Utility			1,086.0	100.00%	410,591	83%	34,565	14%	22	1%			1,132.1			
U.S. Electric LDCS																
CH Energy Group, Inc.	CHG		1,338.1	100.00%	N/A	N/A	N/A	N/A	N/A	N/A		N/A	978.4	N/A	1/1	N/A
Central Hudson Gas & Electric Corp.		NY	798.0	59.64%	244,470	86%	39,057	14%	1,026	0%	288,262	3.03%	898.3	N/A	Yes	*see note [37]*
Consolidated Edison, Inc.	ED		13,941.0	100.00%	N/A	N/A	N/A	N/A	N/A	N/A	3,560,781	N/A	20,874.0	*see note [41]*	4/4	N/A
Consolidated Edison Company of New York, Inc.		NY	10,573.1	75.84%	2,769,280	85%	358,098	11%	129,400	4%	3,261,503	6.39%	19,214.4	N/A	Yes	*see note [42]*
Orange & Rockland Utilities, Inc.		NJ, NY, PA	777.6	5.58%	191,648	86%	30,001	14%	106	0%	222,343	7.28%	949.6	N/A	Yes	*see note [45]*
Pike County Light & Power Company		PA	7.2	0.05%	3,648	79%	981	21%	7	0%	4,642	23.79%	11.9	N/A	Yes	N/A
Rockland Electric Company		NJ	237.7	1.71%	63,115	87%	9,049	13%	119	0%	72,310	2.31%	183.1	N/A	Yes	N/A
DPL Inc.	DPL		1,604.2	100.00%	N/A	N/A	N/A	N/A	N/A	N/A		N/A	2,876.4	N/A	1/1	N/A
Dayton Power and Light Company		OH	1,656.6	103.27%	456,610	90%	50,013	10%	1,804	0%	514,907	14.99%	2,700.3	*see note [46]*	Yes	N/A
Duke Energy Corporation	DUK		13,397.0	100.00%	N/A	N/A	N/A	N/A	N/A	N/A	3,971,510	N/A	34,036.0	*see note [49]*	1/4	*see note [50]*
Duke Energy Carolinas, LLC		NC, SC	5,881.8	43.90%	2,012,004	86%	331,450	14%	7,276	0%	2,364,469	17.73%	15,466.9	*see note [52]*	No	N/A
Duke Energy Indiana, Inc.		IN	2,480.7	18.52%	673,414	88%	89,544	12%	2,842	0%	776,674	24.00%	5,555.6	N/A	No	N/A
Duke Energy Kentucky, Inc.		KY	500.1	3.73%	119,534	90%	13,423	10%	390	0%	134,712	15.21%	862.6	*see note [55]*	No	N/A
Duke Energy Ohio, Inc.		OH	3,167.4	23.64%	611,926	90%	67,601	10%	2,355	0%	687,965	14.95%	6,632.0	*see note [55]*	Yes	N/A
FPL Group, Inc.	FPL		16,487.0	100.00%	N/A	N/A	N/A	N/A	N/A	N/A		N/A	32,411.0	N/A	0/1	N/A
Florida Power & Light Company		FL	11,646.8	70.64%	3,992,262	89%	500,751	11%	13,380	0%	4,509,743	3.00%	16,286.7	*see note [56]*	No	*see note [57]*
MGE Energy Group, Inc.	MGEE		604.0	100.00%	N/A	N/A	N/A	N/A	N/A	N/A		N/A	901.2	N/A	0/1	N/A
Madison Gas and Electric Company		WI	631.5	104.55%	120,464	86%	18,459	13%	436	0%	139,452	5.60%	781.7	*see note [60]*	No	N/A
NSTAR	NST		3,357.6	100.00%	N/A	N/A	N/A	N/A	N/A	N/A		N/A	4,538.2	N/A	1/1	N/A
NSTAR Electric Company		MA	2,902.4	86.44%	977,866	86%	154,759	14%	1,434	0%	1,143,367	5.00%	3,668.8	*see note [63]*	Yes	N/A
Southern Company	SO		17,209.0	100.00%	N/A	N/A	N/A	N/A	N/A	N/A		20.11%	35,878.5	N/A	0/4	*see note [66]*
Alabama Power Company		AL	6,087.4	35.37%	1,212,244	84%	216,510	15%	5,885	0%	1,435,370	N/A	11,833.1	*see note [68]*	No	N/A
Georgia Power Company		GA	8,546.4	49.66%	2,036,557	87%	296,526	13%	8,283	0%	2,346,768	N/A	15,873.6	*see note [70]*	No	N/A
Gulf Power Company		FL	1,387.4	8.06%	374,709	87%	53,810	13%	292	0%	429,304	N/A	2,025.8	N/A	No	N/A
Mississippi Power Company		MS	1,264.7	7.35%	151,611	82%	33,716	18%	517	0%	186,027	N/A	1,282.1	N/A	No	N/A
Average U.S. Electric Dist. Proxy Group			3,443.9	41.06%	941,845	86%	133,162	13%	10,327	0%		11.67%	6,131.0			

Business Profile - Electric Utilities

			[15]	[16]	[17]	[18]
	Ticker	**State/ Province**	**POLR Requirements**	**Planned CapEx (2009-2012)**	**FFO/ CapEx**	**Major Construction Projects**
Ontario Electric LDCs						
Enersource Hydro Mississauga Inc.		Ontario	N/A	*see note [20]*	N/A	*see note [21]*
Horizon Utilities Corporation		Ontario	N/A	*see note [23]*	1.14	*see note [24]*
Hydro One Networks Inc. (Distribution)		Ontario	N/A	*see note [25]*	0.92	*see note [26]*
Hydro Ottawa Limited		Ontario	N/A	*see note [28]*	0.91	*see note [29]*
PowerStream Inc.		Ontario	N/A	*see note [31]*	1.39	*see note [32]*
Toronto Hydro Electric System		Ontario	N/A	*see note [33]*	1.65	*see note [34]*
Veridian Connections Inc.		Ontario	N/A	*see note [35]*	1.39	*see note [36]*
Average Ontario Electric Dist. Utility						
U.S. Electric LDCS						
CH Energy Group, Inc.	CHG		N/A	N/A	1.35	N/A
Central Hudson Gas & Electric Corp.		NY	*see note [38]*	*see note [39]*	1.15	*see note [40]*
Consolidated Edison, Inc.	ED		N/A	N/A	1.26	N/A
Consolidated Edison Company of New York, Inc.		NY	*see note [43]*	*see note [44]*	1.03	N/A
Orange & Rockland Utilities, Inc.		NJ, NY, PA	N/A	N/A	1.15	N/A
Pike County Light & Power Company		PA	N/A	N/A	0.61	N/A
Rockland Electric Company		NJ	N/A	N/A	1.20	N/A
DPL Inc.	DPL		N/A	N/A	2.16	N/A
Dayton Power and Light Company		OH	*see note [47]*	*see note [48]*	2.16	N/A
Duke Energy Corporation	DUK		N/A	*see note [51]*	0.97	N/A
Duke Energy Carolinas, LLC		NC, SC	N/A	N/A	0.81	*see note [53]*
Duke Energy Indiana, Inc.		IN	N/A	N/A	0.88	*see note [54]*
Duke Energy Kentucky, Inc.		KY	N/A	N/A	1.70	N/A
Duke Energy Ohio, Inc.		OH	N/A	N/A	1.64	N/A
FPL Group, Inc.	FPL		N/A	N/A	0.85	N/A
Florida Power & Light Company		FL	N/A	*see note [58]*	0.99	*see note [59]*
MGE Energy Group, Inc.	MGEE		N/A	N/A	1.08	N/A
Madison Gas and Electric Company		WI	N/A	*see note [61]*	0.96	*see note [62]*
NSTAR	NST		N/A	N/A	1.86	N/A
NSTAR Electric Company		MA	*see note [64]*	*see note [65]*	1.25	N/A
Southern Company	SO		N/A	*see note [67]*	1.09	N/A
Alabama Power Company		AL	N/A	*see note [69]*	1.01	N/A
Georgia Power Company		GA	N/A	*see note [71]*	1.12	*see note [72]*
Gulf Power Company		FL	N/A	*see note [73]*	0.65	N/A
Mississippi Power Company		MS	N/A	*see note [74]*	1.30	*see note [75]*
Average U.S. Electric Dist. Proxy Group						

Business Profile - Electric Utilities

Notes:
[1] *see Financial Profile*
[2] Operating company revenue / holding company revenue
[3] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial
U.S. operating companies: 2008 FERC Form 1, page 301; data downloaded from SNL Financial;
[4] Equals Col. [3] / (Col. [3] + Col. [4] + Col. [5])
[5] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks, data downloaded from SNL Financial
U.S. operating companies: 2008 FERC Form 1, page 301; data downloaded from SNL Financial;
[6] Equals Col. [4] / (Col. [3] + Col. [4] + Col. [5])
[7] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks, data downloaded from SNL Financial
U.S. operating companies: 2008 FERC Form 1, page 301; data downloaded from SNL Financial;
[8] Equals Col. [5] / (Col. [3] + Col. [4] + Col. [5])
[9] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks, data downloaded from SNL Financial
U.S. operating companies: 2008 FERC Form 1 & 2008 10-K
[10] Canada: 2008 Annual Reports
U.S. holding companies: N/A
U.S. operating companies: 2008 FERC Form 1, page 300; data downloaded from SNL Financial; equals large or industrial electric sales / total electric operating revenues
[11] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial
U.S. operating companies: 2008 FERC Form 1, page 200; data downloaded from SNL Financial; equals net utility plant
[12] Canada: N/A
U.S. holding companies: 2008 10-Ks
U.S. operating companies: 2008 10-Ks
[13] Canada: N/A
U.S. holding companies: Sum of operating subsidiaries
U.S. operating companies: SNL Financial
[14] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks
U.S. operating companies: 2008 10-Ks
[15] Canada: N/A
U.S. holding companies: N/A
U.S. operating companies: 2008 10-Ks
[16] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks
U.S. operating companies: 2008 10-Ks

[17] Canada: 2008 Annual Reports; equals [net income + interest expense + depreciation and amortization expense + deferred income tax expense] / capital expenditures
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial;
equals [net income + interest expense + depreciation and amortization expense + deferred income tax expense] / capital expenditures
U.S. operating companies: 2008 FERC Form 1, pages 114, 117 and 120; data downloaded from SNL Financial;
equals [net income + net interest charges + depreciation expense + depreciation expense for asset retirement costs + amortization and depletion of utility plant + amortization of utility plant acquisition adjustment + amortization of property losses, unrecovered plant and regulatory study costs + amortization of conversion expenses + provision for deferred income taxes − provision for deferred income taxes (credit)] / cash outflows for plant

[18] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Kx
U.S. operating companies: 2008 10-Ks

[19] Electricity demand is growing at a rate of 2-3% annually (Enersource Corporation Annual Review, page 11)

[20] 35,000 smart meters in 2009 and 35,000 more smart meters in 2010 (Enersource Corporation Annual Review, page 19)

[21] Enersource invested more than $49 million in critical distribution infrastructure assets, with a focus on system reliability, customer care, growth and smart grid technologies including the Integrated Operating Model and smart meters. (Enersource Corporation Annual Review, page 5)

[22] The electricity distribution business operates within a mature and low-growth area
(Horizon Holdings Inc. Management's Discussion and Analysis For the Year Ended December 31, 2008, page 8)

[23] Installation of 96,000 more smart meters by 2010, for a total of 236,000.
(Horizon Holdings Inc. Management's Discussion and Analysis For the Year Ended December 31, 2008, page 5)

[24] Installed approximately 140,000 smart meters by the end of 2008.
In 2008, the Corporation completed its implementation of a new Enterprise Resource Planning ("ERP") software solution to support a migration towards leading and contemporary business processes in the areas of asset, work order, financial, human resources, and supply chain management. Other capital expenditures include facilities, transportation equipment, furniture and office equipment and other work-related equipment. Totaling $42.045 million.
(Horizon Holdings Inc. Management's Discussion and Analysis For the Year Ended December 31, 2008, page 8)

[25] The 2009 capital budgets for Transmission and Distribution Businesses are about $950 million and $650 million, respectively. (Hydro One Annual Report 2008, page 30)

[26] Transmission projects to increase generation and local area supply projects to address growing loads, offset slightly by load and generation projects that were completed or nearing completion in the prior year, $704 million. Distribution projects included development reinforcing of the distribution network including the installation of 496,000 smart meters totaling the 2008 distribution projects to $570 million. (Hydro One Annual Report 2008, pages 29-30)

[27] 4,633 new customers (1.6% increase). (Hydro Ottawa Holding Inc. Annual Report 2008, page 1)

[28] 90% of electric meters recently replaced with smart meters and is continuing to upgrade to smart components. (Hydro Ottawa Holding Inc. Annual Report 2008, page 11)

[29] In 2008, $83.2 million was invested in Hydro Ottawa Limited's electricity distribution and general plant initiatives. In 2008, Hydro Ottawa´s shareholder endorsed a targeted growth strategy involving three basic components: expanding our distribution business beyond our current service territory; and expanding our hydroelectric and other renewable generation capacity. (Hydro Ottawa Holding Inc. Annual Report 2008, pages 6-7)

[30] 9,445 new residential and commercial customers (3.1% increase). (PowerStream 2008 Review, page 40)

[31] Planning to install 180,000 more smart meters by 2010. (Power Stream 2008 Review, page 35)

[32] The capital expenditures for 2008 included $8.1M on smart meters, $5.6M on the new transformer station in Markham and two municipal sub stations and various other road works in the service territory. Planning to outfit all 315,000 customers with smart meters by 2010. (Power Stream 2008 Review, page 33)

[33] Installation of 124,000 more smart meters by 2010. (Consolidated Financial Statements, Toronto Hydro Corporation, December 31, 2008, page 21)

[34] The project objective is to install 711,000 smart meters and the supporting infrastructure by the end of 2010. LDC has installed approximately 587,000 meters as at December 31, 2008.
In connection with its smart meter initiatives, the Corporation has incurred costs amounting to $34,125,000 for the year ended December 31, 2008.
(Consolidated Financial Statements, Toronto Hydro Corporation, December 31, 2008, page 21-22)

[35] Veridian has a strategic objective of growth by acquisition or merger. The current transfer tax exemption is a significant incentive for acquisitions or mergers to occur. Merger or acquisition opportunities may arise during 2009. Mergers or acquisitions by municipally owned local distribution companies will be exempt from a 33 percent transfer tax up to October 17, 2009. (Veridian Corporation 2008 Annual Report, page 27)

[36] Installation of smart meters, with 75,000 now installed at December 31, 2008. (Veridian Corporation 2008 Annual Report, page 19)

[37] Experienced 0.9% growth of customer base in 2008. (CHG 2008 10-K, page 28)

[38] Central Hudson procures supplies of electricity and natural gas for customers who have not chosen to utilize an independent third party supplier. (CHG 2008 10-K, page 27)

[39] Central Hudson's planned capital expenditures for construction and removal during 2009 are expected to total approximately $110 million. For 2010, planned capital expenditures are expected to range from $95 million to $105 million. (CHG 2008 10-K, page 74)

[40] Central Hudson is seeking authorization for regulated utilities to own electric generation facilities powered by renewable resources. (CHG 2008 10-K, page 30)

[41] The company plans to meet its continuing obligation to supply electricity to its customers with electric energy purchased under contracts with non-utility generators (NUGs) or others, purchased through the NYISO's wholesale electricity or generated from its electric generating facilities. (ED 2008 10-K, page 9)

[42] The average annual growth rate of the peak electric demand over the next five years at design conditions is estimated to be approximately 0.6 percent for Con Edison of New York. (ED 2008 10-K, page 27)

[43] Con Edison of New York is primarily a "wires and pipes" energy delivery company that provides its customers with the opportunity to buy electricity and gas from other suppliers but purchases substantially all of the electricity and all of the gas it sells to its full-service customers. (ED 2008 10-K, page 11)

[44] The utilities estimate that their construction expenditures will exceed $7 billion over the next three years. The ongoing construction program includes large energy transmission, substation and distribution system projects. (ED 2008 10-K, page 30)

[45] The average annual growth rate of the peak electric demand over the next five years at design conditions is estimated to be approximately 2.1 percent for O&R. (ED 2008 10-K, page 27)

[46] DPL has substantially all of the total expected coal volume needed to meet its retail and firm wholesale sales requirements for 2009 under contract. (DPL 2008 10-K, page 7)

[47] DP&L continues to have the exclusive right to provide delivery service in its state certified territory and the obligation to supply retail generation service to customers that do not choose an alternative supplier. (DPL 2008 10-K, page 8)

[48] For 2009, DPL is projecting to spend approximately $150 million on capital expenditures relating primarily to its transmission and distribution system, plant and equipment and its environmental compliance program. DPL's future capital expenditures are expected to decrease relative to prior years and are projected to approximate a total of $475 million for the three-year period 2009, 2010 and 2011. (DPL 2008 10-K, page 50)

[49] The vast majority of customer energy needs are met by large, low-energy-production-cost nuclear and coal-fired generating units that operate almost continuously (or at baseload levels). In 2008, approximately 99.0% of the total generated energy came from U.S. Franchised Electric and Gas' low-cost, efficient nuclear and coal units (66.9% coal and 32.1% nuclear). The remaining energy needs were supplied by hydro electric, CT and CC generation or economic purchases from the wholesale market. U.S. Franchised Electric and Gas has an adequate supply of coal to fuel its projected 2009 operations and a significant portion of supply to fuel its projected 2010 operations. (DUK 2008 10-K, page 10)

[50] The number of residential and general service customers within the U.S. Franchised Electric and Gas' service territory continues to increase. As a result, sales to these customers are increasing due to growth in these sectors, although near-term growth is being hampered by the current economic conditions. As sales to residential and commercial customers are expected to increase over the coming years, the level of sales to industrial customers becomes a smaller, yet still significant, portion of U.S. Franchised Electric and Gas Sales. (DUK 2008 10-K, page 9)

[51] Approximately 75 percent of total projected 2009 capital expenditures are allocated to the U.S. Franchised Electric and Gas segment. Total U.S. Franchised Electric and Gas projected 2009 capital and investment expenditures include approximately $1.9 billion for system growth, $1.5 billion for maintenance and upgrades of existing plants and infrastructure to serve load growth, approximately $0.2 billion of environmental expenditures, and approximately $0.2 billion of nuclear fuel. During the five-year period from 2009 to 2013, Duke Energy anticipates cumulative capital expenditures of approximately $25 billion. (DUK 2008 10-K, page 29)

[52] Duke Energy Carolinas has entered into fuel contracts that, based on its current need projections, cover 100% of the uranium concentrates, conversion services, and enrichment services requirements of the Oconee, McGuire and Catawba Nuclear Stations through at least 2011 and cover fabrication services requirements for these plants through at least 2016. (DUK 2008 10-K, page 14)

[53] William States Lee III Nuclear Station -- On December 12, 2007, Duke Energy Carolinas filed an application with the Nuclear Regulatory Commission (NRC) for a combined construction and operating license (COL) for two Westinghouse AP1000 (advanced passive) reactors for the proposed William States Lee III Nuclear Station at a site in Cherokee County, South Carolina. Duke Energy Carolinas estimates up to $230 million in pre-construction development costs through 2009.

Cliffside Unit 6 -- On June 2, 2006, Duke Energy Carolinas filed an application with the NCUC for a Certificate of Public Convenience and Necessity (CPCN) to construct two 800 MW state of the art coal generation units at its existing Cliffside Steam Station in North Carolina. On March 21, 2007, the NCUC issued an Order allowing Duke Energy Carolinas to build one 800 MW unit with an approved cost estimate of $1.93 billion.

Dan River and Buck Steam Stations -- On June 29, 2007, Duke Energy Carolinas filed with the NCUC preliminary CPCN information to construct a 620 MW combined cycle natural gas-fired generating facility at its existing Dan River Steam Station, as well as updated preliminary CPCN information to construct a 620 MW combined cycle natural gas-fired generating facility at its existing Buck Steam Station. Duke Energy Carolinas entered into an engineering, construction and commissioning services agreement valued at approximately $275 million. On November 5, 2008, Duke Energy Carolinas notified the NCUC that since the issuance of the CPCN Order, recent economic factors have caused increased uncertainty with regard to forecasted load and near-term capital expenditures, which has resulted in a modification of the construction schedule. Under the revised schedule, the Buck Project is expected to be delayed for a period of up to one year and is currently anticipated to begin operation in simple cycle mode in summer 2011 and is expected to convert to combined cycle mode in summer 2012. The Dan River Project is expected to begin operation in combined cycle mode in 2012 as originally planned, but without a phased-in simple cycle commercial operations. (DUK 2008 10-K, pages 11-12)

[54] Edwardsport IGCC -- On November 20, 2007, the IURC issued an order granting Duke Energy Indiana a CPCN for the proposed 630 MW IGCC power plant at Duke Energy Indiana's Edwardsport Generating Station in Knox County, Indiana. The updated cost estimate is $2.35 billion. (DUK 2008 10-K, page 12)

[55] As of December 31, 2008, Duke Energy Ohio and Duke Energy Kentucky, combined, had locked in pricing for approximately 24% of their winter 2008/2009 system load requirements. (DUK 2008 10-K, page 13)

[56] FPL's projected reserve margin for the summer of 2009 is approximately 28%. This reserve margin is expected to be achieved through the combination of output from FPL's active generating units, purchased power contracts and the capability to reduce peak demand through the implementation of load management, which was estimated to be capable of reducing demand by 1,734 MW at December 31, 2008. (FPL 2008 10-K, page 7)

[57] Over the last ten years, FPL's average annual customer growth has been 2.1%. However, beginning in 2007, FPL has experienced a slowdown in retail customer growth and a decline in non-weather related usage per retail customer. Retail customer growth in 2008 was 0.3%, although during the fourth quarter of 2008 FPL experienced a decline in customer accounts of 0.2%. (FPL 2008 10-K, page 28)

[58] 2009: $2,925 million ($1,350 new generation; $665 existing generation; $615 transmission and distribution; $125 nuclear fuel; $170 general and other)
2010: $3,395 million ($1,355 new generation; $680 existing generation; $865 transmission and distribution; $205 nuclear fuel; $290 general and other)
2011: $2,825 million ($760 new generation; $610 existing generation; $925 transmission and distribution; $215 nuclear fuel; $315 general and other)
2012: $2,320 million ($355 new generation; $515 existing generation; $930 transmission and distribution; $220 nuclear fuel; $300 general and other)
2013: $1,945 million ($40 new generation; $430 existing generation; $975 transmission and distribution; $265 nuclear fuel; $235 general and other)
(FPL 2008 10-K, page 93)

[59] FPL is currently constructing three natural gas-fired combined-cycle units of approximately 1,220 MW each at its West County Energy Center, which units are expected to be placed in service by the third quarter of 2009, fourth quarter of 2009 and mid-2011. The estimated total cost of the three units is $2.2 billion. In 2008, FPSC approved FPL's plan to modernize its Cape Canaveral and Riviera power plants to high-efficiency natural gas-fired units. Each modernized plant is expected to provide approximately 1,200 MW of capacity and be placed into service by 2013 and 2014 at a cost of $1.1 billion and $1.3 billion, respectively. FPL is in the process of adding approximately 400 MW of baseload capacity at its existing nuclear units at St. Lucie and Turkey Point, which additional capacity is projected to be placed in service by the end of 2012 at an estimated total cost of $1.6 billion. In 2008, the FPSC approved FPL's need petition for two additional nuclear units at its Turkey Point site with projected in-service dates between 2018 and 2020, which units are expected in the aggregate to add between 2,200 MW and 3,040 MW of baseload capacity. In 2008, the FPSC approved FPL's proposal to construct three solar generating facilities, which are expected to have a capacity totaling 110 MW. The solar generating facilities are expected to be placed into service by the end of 2010 at an estimated total cost of $728 million.
(FPL 2008 10-K, pages 7-8)

[60] In 2008, 51.9% of electric energy delivery requirements were fulfilled by MGE's internal generation, 39.2% was fulfilled by purchased power. MGE has entered into several long-term purchase power agreements to meet future power demands. (MGEE 2008 10-K, pages 9-10)

[61] 2009 capital expenditure budget: $42,586 thousand (electric utility plant), $18,414 thousand (gas utility plant), $22,834 (nonregulated). (MGEE 2008 10-K, page 45)

[62] MGE owns an undivided 8.33% ownership interest in each of two 615 MW advanced technology, coal-fired generating units being constructed by Wisconsin Energy Corporation in Oak Creek, Wisconsin. The target in-service date for Elm Road unit 1 is three months beyond the guaranteed contract date of September 29, 2009. The target in-service date for Elm Road unit 2 is one month earlier than the guaranteed contract of September 29, 2010. MGEE's share of capital costs is approximately $172 million. (MGEE 2008 10-K, pages 11-12)

[63] NSTAR Electric enters into short-term power purchase agreements to meet its Basic Service supply obligation, ranging in term from three to twelve months. (NST 2008 10-K, page 7)

[64] Electric distribution companies in Massachusetts are required to obtain and resell power to retail customers through Basic Service for those who choose not to buy energy from a competitive energy supplier. (NST 2008 10-K, page 6)

[65] 2009: $365 million ($100 million for transmission system improvements)
2010-2013: $1,255 million (system reliability and performance improvements, customer service enhancements, and capacity expansion in NSTAR's service territory)
(NST 2008 10-K, page 10)

[66] 2008 customer growth was 0.6% (SO 2008 10-K, page II-17)

[67] Southern Company is engaged in continuous construction programs, currently estimated to total $5.7 billion in 2009, $5.1 billion in 2010, and $5.8 billion in 2011. (SO 2008 10-K, page II-96)

[68] The traditional operating companies' supply of electricity is derived predominantly from coal and have agreements in place from which they expect to receive approximately 100% of their coal burn requirements in 2009. (SO 2008 10-K, page I-5)

[69] 2009: $1,414 million ($584 environmental; $232 other generating facilities; including associated plant substations; $196 new business; $76 transmission; $157 distribution; $90 nuclear fuel; $79 general plant). The Company is engaged in continuous construction programs, currently estimated to total $1.4 billion in 2009, $1.0 billion in 2010, and $1.0 billion in 2011. (SO 2008 10-K, pages I-4 & II-164)

[70] Triennially, Georgia Power must file an IRP with the Georgia PSC that specifies how it intends to meet the future electrical needs of its customers through a combination of demand-side and supply-side resources. (SO 2008 10-K, page I-12)

[71] 2009: $2,754 million ($1,209 new generation; $472 environmental; $178 other generating facilities, including associated plant substations; $170 new business, $313 transmission; $189 distribution; $148 nuclear fuel; $75 general plant). The Company currently estimates property additions to be approximately $2.8 billion, $2.6 billion, and $2.6 billion in 2009, 2010, and 2011, respectively. (SO 2008 10-K, pages I-4 & II-232)

[72] On August 1, 2008, Georgia Power submitted an application for the Georgia PSC to certify two additional nuclear units on the site of Plant Vogtle. If certified by the Georgia PSC and licensed by the NRC, Vogtle Units 3 and 4 are scheduled to be placed in service in 2016 and 2017, respectively. Georgia Power's proportionate share of the estimated in-service costs is approximately $6.4 billion. (SO 2008 10-K, page II-37)

[73] 2009: $478 million ($6 new generation; $335 environmental; $42 other generating facilities, including associated plant substations; $29 new business, $25 transmission; $29 distribution; $12 general plant). The Company is engaged in a continuous construction program, the cost of which is currently estimated to total $478 million in 2009, $337 million in 2010, and $400 million in 2011. (SO 2008 10-K, pages I-4 & II-293)

[74] 2009: $163 million ($48 new generation; $28 environmental; $11 other generating facilities, including associated plant substations; $16 new business, $20 transmission; $30 distribution; $10 general plant). The Company is engaged in continuous construction programs, currently estimated to total $163 million in 2009, $467 million in 2010, and $1.0 billion in 2011. (SO 2008 10-K, pages I-4 & II-358)

[75] On January 16, 2009, Mississippi Power filed for a Certificate of Public Convenience and Necessity with the Mississippi PSC to allow construction of a new electric generating plant located in Kemper County, Mississippi. The plant would utilize an advanced coal IGCC with an output capacity of 582 megawatts at an estimated cost of $2.2 billion. (2008 10-K, page I-13)

Business Profile - Gas Utilities

			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
					Customer Mix										
	Ticker	**State/ Province**	**Revenue**	**% of Total Revenue**	**Residential**	**%**	**Commercial**	**%**	**Industrial**	**%**	**Total Customers**	**Industrial Revenue / Total Revenue**	**Net Plant**	**Storage Capacity (Bcf)**	**% Service Territory Growth**
Ontario Gas LDCs															
Enbridge Inc.	ENB		16,131.3	100.00%	N/A	N/A	N/A	N/A	N/A	N/A		N/A	16,389.6	N/A	N/A
Enbridge Gas Distribution Inc.		Ontario	3,011.0	18.67%	1,114,878	91%	105,056	9%	3,912	0%	1,900,000	N/A	3,660.7	95.2	*see note [18]*
Spectra Energy Corporation	SE		5,074.0	100.00%	N/A	N/A	N/A	N/A	N/A	N/A		N/A	13,639.0	270.0	N/A
Union Gas Limited		Ontario	2,130.0	41.98%	N/A	N/A	N/A	N/A	N/A	N/A	1,300,000	N/A	3,827.0	155.0	*see note [21]*
Average Ontario Gas Dist. Utility			257050.00%	30.32%	1,114,878	91%	105,056	9%	3,912	0%			3,743.9	125.1	
U.S. Gas LDCs															
AGL Resources Inc.	AGL		2,806.0	100.00%	N/A	N/A	N/A	N/A	N/A	N/A		N/A	3,816.0	17.8	*see note [25]*
Atlanta Gas Light Company		GA	606.1	21.60%	N/A	N/A	N/A	N/A	N/A	N/A	1,557,000	N/A	2,077.8	N/A	N/A
Chattanooga Gas Company		TN	124.5	4.44%	N/A	N/A	N/A	N/A	N/A	N/A	62,000	N/A	108.8	N/A	N/A
Elizabethtown Gas		NJ	523.5	18.66%	N/A	N/A	N/A	N/A	N/A	N/A	273,000	N/A	593.5	N/A	N/A
Elkton Gas		MD	14.7	0.53%	5,533	92%	480	8%	4	0%	6,000	51.28%	8.2	N/A	N/A
Florida City Gas		FL	93.3	3.32%	97,437	96%	4,552	4%	0	0%	104,000	N/A	145.1	N/A	N/A
Virginia Natural Gas, Inc.		VA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	271,000	N/A	N/A	N/A	N/A
Piedmont Natural Gas Company, Inc.	PNY	NC, SC, TN	2,118.1	100.00%	852,586	90%	94,045	10%	2,974	0%	949,605	12.00%	2,241.7	N/A	*see note [30]*
South Jersey Industries, Inc.	SJI		963.3	100.00%	N/A	N/A	N/A	N/A	N/A	N/A		N/A	982.6	0.0	N/A
South Jersey Gas Company		NJ	568.0	58.97%	314,374	93%	22,440	7%	289	0%	340,136	3.39%	876.6	0.0	*see note [34]*
Sempra Energy	SRE		11,456.0	100.00%	N/A	N/A	N/A	N/A	N/A	N/A		N/A	16,865.0	142.4	N/A
Mobile Gas Service Corporation		AL	108.5	0.95%	N/A	N/A	N/A	N/A	N/A	N/A	93,000	N/A	124.9	0.0	N/A
San Diego Gas & Electric Co.		CA	3,306.9	28.87%	N/A	N/A	N/A	N/A	N/A	N/A	3,100,000	N/A	5,307.1	0.0	*see note [38]*
Southern California Gas Company		CA	4,759.4	41.55%	N/A	N/A	N/A	N/A	N/A	N/A	5,700,000	N/A	5,130.7	131.0	*se note [41]*
Southwest Gas Corporation	SWX	AZ, CA, NV	2,131.3	100.00%	N/A	N/A	N/A	N/A	N/A	N/A	1,819,000	14.00%	2,983.3	N/A	*see note [44]*
Vectren Corporation	VVC		2,524.2	100.00%	N/A	N/A	N/A	N/A	N/A	N/A		N/A	3,110.5	12.3	N/A
Indiana Gas Company, Inc.		IN	865.0	34.27%	517,475	91%	49,961	9%	855	0%	568,000	N/A	759.2	6.0	N/A
Southern Indiana Gas and Electric Company, Inc.		IN	683.9	27.09%	100,844	91%	9,983	9%	146	0%	111,000	N/A	1,355.4	6.3	N/A
Vectren Energy Delivery of Ohio, Inc.		OH	408.1	16.17%	291,663	92%	23,373	7%	681	0%	317,000	N/A	459.1	0.0	N/A
Average U.S. Gas Dist. Proxy Group			1,165.1	32.60%	311,416	92%	29,262	8%	707	0%		20.17%	1,583.7	20.5	

Business Profile - Gas Utilities

	Ticker	State/ Province	[14] Risk of Bypass	[15] Planned CapEx (2009-2012)	[16] FFO/ CapEx	[17] Major Construction Projects
Ontario Gas LDCs						
Enbridge Inc.	ENB		N/A	N/A	N/A	N/A
Enbridge Gas Distribution Inc.		Ontario	*see note [19]*	*see note [20]*	1.62	N/A
Spectra Energy Corporation	SE		N/A	N/A	N/A	N/A
Union Gas Limited		Ontario	*see note [22]*	*see note [23]*	1.80	*see note [24]*
Average Ontario Gas Dist. Utility						
U.S. Gas LDCs						
AGL Resources Inc.	AGL		*see note [26]*	*see note [27]*	1.59	N/A
Atlanta Gas Light Company		GA	N/A	N/A	1.77	*see note [28]*
Chattanooga Gas Company		TN	N/A	N/A	1.43	N/A
Elizabethtown Gas		NJ	N/A	N/A	1.64	*see note [29]*
Elkton Gas		MD	N/A	N/A	1.31	N/A
Florida City Gas		FL	N/A	N/A	N/A	N/A
Virginia Natural Gas, Inc.		VA	N/A	N/A	N/A	*see note [27]*
Piedmont Natural Gas Company, Inc.	PNY	NC, SC, TN	*see note [31]*	*see note [32]*	1.60	*see note [33]*
South Jersey Industries, Inc.	SJI		N/A	N/A	2.50	N/A
South Jersey Gas Company		NJ	*see note [35]*	*see note [36]*	1.96	N/A
Sempra Energy	SRE		*see note [37]*	N/A	1.16	N/A
Mobile Gas Service Corporation		AL	N/A	N/A	1.77	N/A
San Diego Gas & Electric Co.		CA	N/A	*see note [39]*	1.27	*see note [40]*
Southern California Gas Company		CA	N/A	*see note [42]*	1.48	*see note [43]*
Southwest Gas Corporation	SWX	AZ, CA, NV	*see note [45]*	*see note [46]*	1.27	N/A
Vectren Corporation	VVC		N/A	*see note [47]*	1.28	N/A
Indiana Gas Company, Inc.		IN	N/A	N/A	N/A	N/A
Southern Indiana Gas and Electric Company, Inc.		IN	N/A	N/A	0.85	*see note [48]*
Vectren Energy Delivery of Ohio, Inc.		OH	N/A	N/A	N/A	N/A
Average U.S. Gas Dist. Proxy Group						

Business Profile - Gas Utilities

Notes:

[1] *see Financial Profile*
[2] Operating company revenue / holding company revenue
[3] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial
U.S. operating companies: 2008 Gas LDC Filings, page 301; data downloaded from SNL Financial;
[4] Equals Col. [3] / (Col. [3] + Col. [4] + Col. [5])
[5] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks, data downloaded from SNL Financial
U.S. operating companies: 2008 Gas LDC Filings; data downloaded from SNL Financial;
[6] Equals Col. [4] / (Col. [3] + Col. [4] + Col. [5])
[7] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks, data downloaded from SNL Financial
U.S. operating companies: 2008 Gas LDC Filings; data downloaded from SNL Financial;
[8] Equals Col. [5] / (Col. [3] + Col. [4] + Col. [5])
[9] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks, data downloaded from SNL Financial
U.S. operating companies: 2008 FERC Form 1 & 2008 10-K
[10] Canada: 2008 Annual Reports
U.S. holding companies: N/A
U.S. operating companies: 2008 10-Ks and 2008 Gas LDC Filings; data downloaded from SNL Financial; equals large or industrial electric sales / total electric operating revenues
[11] Canada: 2008 Annual Report
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial
U.S. operating companies: 2008 Gas LDC Filings; data downloaded from SNL Financial; equals net utility plant
[12] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks
U.S. operating companies: 2008 10-Ks
[13] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks
U.S. operating companies: 2008 10-Ks
[14] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks
U.S. operating companies: 2008 10-Ks
[15] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks
U.S. operating companies: 2008 10-Ks
[16] Canada: 2008 Annual Reports; equals [net income + interest expense + depreciation and amortization expense + deferred income tax expense] / capital expenditures
U.S. holding companies: 2008 10-Ks; data downloaded from SNL Financial;
equals [net income + interest expense + depreciation and amortization expense + deferred income tax expense] / capital expenditures
U.S. operating companies: 2008 FERC Form 1, pages 114, 117 and 120; data downloaded from SNL Financial;
equals [net income + net interest charges + depreciation expense + depreciation expense for asset retirement costs + amortization and depletion of utility plant + amortization of utility plant acquisition adjustment + amortization of property losses, unrecovered plant and regulatory study costs + amortization of conversion expenses + provision for deferred income taxes − provision for deferred income taxes (credit)] / cash outflows for plant
[17] Canada: 2008 Annual Reports
U.S. holding companies: 2008 10-Ks
U.S. operating companies: 2008 10-Ks

[18] Average 44,026 customers/year over past three years. The Ontario franchise area remains one of the most rapidly growing regions in North America. The Company will continue to grow its natural gas distribution business by adding customers to existing infrastructure and through geographic extension of the distribution system. (Enbridge Gas Distribution Inc. Annual Information Form For the Year Ended December 31, 2008, page 11)

[19] Low. Natural gas is the predominant fuel of choice in the residential heating market throughout the Company's franchise area. The primary competition for natural gas remains domestic fuel oil and electricity. Natural gas has continued to provide both environmental and price advantages, and this is expected to continue. (Enbridge Gas Distribution Inc. Annual Information Form For the Year Ended December 31, 2008, page 10)

[20] Capital expenditures are expected to be $389 million in 2009 as EGD completes laterals for new power generating facilities, and builds its CIS system. (Enbridge Inc. 2008 Annual Report, page 52)

[21] Grew from 1,289,000 (2007) customers to 1,309,000 (2008). Although Union's customer base is expected to decline as a result of the current economy, management expects overall demand for natural gas in North America to grow at a long-term rate of one percent per year along with continued growth in peak day demands. (Union Gas Limited Annual Report 2008, page 16)

[22] As Union's distribution business is regulated by the OEB, it is generally not subject to third-party competition within Union's distribution franchise area. However, as a result of a 2006 decision by the OEB, physical bypass of Union's facilities even within its distribution franchise area may be permitted. In addition, other companies could enter Union's markets or regulations could change. (Union Gas Limited Annual Report 2008, page 19)

[23] $285 million -- 44% to storage and transmission projects, 46% distribution, 10% general equipment. (Union Gas Limited Annual Report 2008, page 11)

[24] Union Gas conducted an open season during the July to September, 2008 period to solicit market interest for transmission service on the Dawn-Trafalgar transmission system and targeted an in-service date for a proposed expansion in the fourth quarter of 2010. Given current economic circumstances and delays experienced with 2008 expansion projects, Union Gas expects to pursue this expansion to service these new demands in 2011. (Union Gas Limited Annual Information Form For the Year Ended December 31, 2008, page 10)

[25] Due to the general economic downturn and the decline in the housing markets in the areas AGL serves, AGL experienced lower than expected customer growth throughout 2008, (0.1% versus 0.5% anticipated growth) a trend they expect to continue through 2009. This trend has been offset slightly by growth in the commercial customer segment in certain areas, primarily as a result of conversions to natural gas from other fuel sources. In addition, AGL continue to experience some customer loss because of higher natural gas prices and competition from alternative fuel sources, including incentives offered by the local electric utilities to switch to electric alternatives. (ALG 2008 10-K, page 9)

[26] AGL's principal competition is from electric utilities and oil and propane providers serving the residential and commercial markets throughout its service areas and the potential displacement or replacement of natural gas appliances with electric appliances. The primary competitive factors are the prices for competing sources of energy as compared to natural gas and the desirability of natural gas heating versus alternative heating sources. (AGL 2008 10-K, page 8)

[27] 2009: estimated PP&E expenditures of approximately $453 million ($119 base business; $116 natural gas storage; $83 Virginia Natural Gas' Hampton Roads pipeline project to connect its northern and southern systems; $49 Atlanta Gas Light's program to replace all bare steel and cast iron pipe in its Georgia system; $48 Magnolia pipelines acquired from Southern Natural Gas connecting Georgia service territory to the Elba Island LNG Facility; $38 other expenditures including information technology, building and leasehold improvements and AGL Network's telecommunications expenditures). (AGL 2008 10-K, page 36)

[28] Atlanta Gas Light was ordered by the Georgia Commission to undertake a pipeline replacement program (PRP) that would replace all bare steel and cast iron pipe in its system by December 2013. Approximately 68 miles of cast iron and 420 miles of bare steel pipe still require replacement. Atlanta Gas Light has recorded a long-term regulatory asset of $196 million, which represents the expected future collection of both expenditures already incurred and expected future capital expenditures to be incurred through the remainder of the program. (AGL 2008 10-K, page 41 & 63)

[29] In August 2006, the New Jersey Commission issued an order adopting a pipeline replacement cost recovery rider program for the replacement of certain 8" cast iron main pipes and any unanticipated 10"-12" cast iron main pipes integral to the replacement of the 8" main pipes. Total replacement costs through December 31, 2008 were $21 million. (AGL 2008 10-K, page 64)

[30] Piedmont remains one of the fastest growing natural gas utilities in the nation for customer additions. Piedmont added 20,506 new customers to their distribution system in 2008, a gross new customer addition growth rate of 2%. (PNY 2008 10-K, page 15)

[31] Certain large volume customers located in proximity to the interstate pipelines delivering gas to us could bypass us and take delivery of gas directly from the pipeline or from a third party connecting with the pipeline. During the fiscal year ended October 31, 2008, no bypass activity was experienced. Piedmont also competes with other energy products, such as electricity and propane, in the residential and small commercial customer markets. The most significant product competition is with electricity for space heating, water heating and cooking. Piedmont continues to attract the majority of the new residential construction market on or near Piedmont's distribution mains. (PNY 2008 10-K, pages 4-5)

[32] Gross utility construction expenditures totaling $246.2 million, primarily to serve future customer growth, are budgeted for 2009. (PNY 2008 10-K, page 24)

[33] Piedmont intends to design, construct, own and operate a LNG peak storage facility as a regulated utility project in Robeson County, North Carolina with the capacity to store approximately 1.25 billion cubic feet of natural gas for use during times of peak demand. The LNG facility is planned to be in service for the 2012-2013 winter heating season. Preliminary estimates place the cost of the facility in the $300 million to $350 million range. (PNY 2008 10-K, page 24)

[34] In recent years, housing growth in the eastern portion of the service territory increased substantially and currently accounts for approximately half of SJG's annual customer growth. The ripple effect from Atlantic City typically produces new housing, commercial and industrial construction. Combining with the gaming industry catalyst has been the ongoing conversion of southern New Jersey's oceanfront communities from seasonal resorts to year round economies. New and expanded hospitals, schools, and large scale retail developments throughout the service territory have contributed to SJG's growth. Consumers converting from other heating fuels, such as electric, propane or oil have historically accounted for 20-25% of annual SJG customer growth. (SJI 2008 10-K, page SJI-15)

[35] SJG's franchises are non-exclusive. Currently, no other utility provides retail gas distribution services within SJG's territory. SJG does not expect any other utilities to do so in the foreseeable future because of the extensive investment required for utility plant and related costs. SJG competes with oil, propane and electricity suppliers for residential, commercial and industrial users, with alternative fuel source providers based upon price, convenience and environmental factors, and with other marketers/ brokers in the selling of wholesale natural gas service. (SJI 2008 10-K, page SJI-22)

[36] SJI estimates the net cash outflows for construction projects for 2009, 2010 and 2011 to be approximately $140.3 million, $95.4 million and $58.5 million, respectively. (SJI 2008 10-K, page SJI-32)

[37] The Sempra Utilities face competition in the residential and commercial customer markets based on the customers' preferences for natural gas compared with other energy products. In the noncore industrial market, some customers are capable of securing alternate fuel supplies from other suppliers which can affect the demand for natural gas. The Sempra Utilities' ability to maintain their respective industrial market shares is largely dependent on the relative spread between delivered energy prices. (SRE 2008 10-K, page 10)

[38] In 2008, SDG&E added 3,000 new customer natural gas meters at a growth rate of 0.4 percent; in 2007, it added 5,000 new meters at a growth rate of 0.7 percent. SDG&E expects that its growth rate will continue to decline in 2009 based on housing market forecasts and due to the continuing economic downturn. (SRE 2008 10-K, page 11)

[39] In 2009, Sempra expects to make capital expenditures and investments of $800 million at SDG&E ($500 additions to natural gas and electric distribution generation systems, and advanced metering infrastructure; $200 improvements to electric transmission infrastructure; $100 Sunrise Powerlink transmission line). Over the next five years, SDG&E expects to make capital expenditures of $5.8 billion at an average rate of $1.17 billion per year. (SRE 2008 10-K, page 34)

[40] SDG&E completed the initial installation of 4,500 advanced meters and is on schedule to complete the full installation of 1.4 million electric meters and 900,000 natural gas meters by the end of 2011. SDG&E estimates expenditures for this project of $572 million. (SRE 2008 10-K, page 8)

[41] In 2008, SoCalGas added 41,000 new customer natural gas meters at a growth rate of 0.7 percent; in 2007, it added 57,000 new meters at a growth rate of 1.0 percent. SoCalGas expects that its growth rate will continue to decline in 2009 based on housing market forecasts and due to the continuing economic downturn. (SRE 2008 10-K, page 11)

[42] In 2009, Sempra expects to make capital expenditures and investments of $500 million at SoCalGas ($500 improvements to distribution and transmission systems, and for advanced metering infrastructure). Over the next five years, SoCalGas expects to make capital expenditures of #3.2 billion at an average rate of $650 million per year. (SRE 2008 10-K, page 34)

[43] SoCalGas requested approval from the CPUC to upgrade approximately 6 million natural gas meters with advanced metering infrastructure at an estimated cost of $1.1 billion. A final CPUC decision is expected late in 2009. If approved as scheduled, installation of the meters is expected to begin in 2011 and continue through 2015. (SRE 2008 10-K, page 172)

[44] The southwestern United States has historically been one of the highest growth regions of the country. However, the customer growth levels experienced in recent years have greatly diminished due to the overall slowdown in the new housing market and idle/vacant homes due to foreclosures and challenging economic conditions. First-time meter sets of 33,000 were substantially offset by temporarily vacated homes. There were 6,000 net new customers added to the system during 2008, an increase of less than one-half of one percent. Given the current housing and economic downturn, management expects customer growth will approximate one percent in the near term. Management cannot predict the timing of when currently idle and vacant homes will return to service, or when customer growth levels will improve, but it is likely to occur over an extended (multi-year) time horizon. (SWX 2008 10-K, page 1)

[45] Unlike residential and small commercial customers, certain large commercial, industrial, and electric generation customers have the capability to switch to alternative energy sources. To date, Southwest has been successful in retaining most of these customers by setting rates at levels competitive with commercially available alternative energy sources such as electricity, fuel oils, and coal. However, high natural gas prices can impact Southwest's ability to retain some of these customers. Southwest competes with interstate transmission pipeline companies, such as El Paso, Kern River, Transwestern and Tuscarora, to provide service to certain large end-users. End-use customers located in proximity to these interstate pipelines pose a potential bypass threat. Southwest attempts to closely monitor each customer situation and provide competitive service in order to retain the customer.(SWX 2008 10-K, pages 4-5)

[46] Southwest estimates natural gas segment construction expenditures during the three-year period ending December 31, 2011 will be approximately $720 million. Of this amount, approximately $260 million are expected to be incurred in 2009. (SWX 2008 10-K, page 27)

[47] Planned capital expenditures and investments for the five-year period 2009-2013 for the utility group:
2009: $250 million; 2010: $265 million; 2011: $255 million; 2012: $270 million; 2013: $245 million (VVC 2008 10-K, page 47)

[48] SIGECO is currently constructing an interstate 345 kilovolt transmission line that will connect Vectren's A B Brown Station to a station in Indiana owned by Duke Energy to the north and to a station in Kentucky owned by Big Rivers Electric Corporation to the south. The Company expects this project to be operational in 2011 at a total cost of $70 million. (VVC 2008 10-K, page 36)

90-DAY CONSTANT GROWTH DCF - U.S. NATURAL GAS DISTRIBUTION UTILITIES

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Bloomberg Long-Term Growth	Thomson First Call Growth Estimate	Zacks Earnings Growth Estimate	Value Line Earnings Growth Estimate	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
U.S. NATURAL GAS DISTRIBUTION UTILITIES													
AGL Resources Inc.	AGL	$1.72	$30.13	5.71%	5.82%	4.25%	4.25%	5.30%	3.50%	4.05%	9.31%	9.87%	11.16%
Piedmont Natural Gas Company, Inc.	PNY	$1.08	$24.26	4.45%	4.59%	5.76%	6.20%	6.60%	6.00%	6.09%	10.34%	10.68%	11.20%
Sempra Energy	SRE	$1.56	$47.29	3.30%	3.39%	6.36%	6.61%	6.50%	5.00%	5.75%	8.38%	9.14%	10.02%
South Jersey Industries, Inc.	SJI	$1.19	$34.86	3.41%	3.54%	8.33%	9.67%	9.50%	5.50%	7.33%	9.01%	10.87%	13.25%
Southwest Gas Corporation	SWX	$0.95	$21.41	4.44%	4.56%	5.00%	6.00%	6.00%	5.00%	5.33%	9.55%	9.89%	10.57%
Vectren Corporation	VVC	$1.34	$22.55	5.94%	6.12%	6.33%	6.43%	7.10%	5.50%	6.06%	11.61%	12.18%	13.25%
PROXY GROUP MEAN		$1.31	$30.08	4.54%	4.67%	6.00%	6.53%	6.83%	5.08%	5.77%	9.70%	10.44%	11.57%
PROXY GROUP MEDIAN		$1.27	$27.20	4.44%	4.57%	6.04%	6.32%	6.55%	5.25%	5.90%	9.43%	10.28%	11.18%

Flotation Cost Adjustment	0.50%	0.50%	0.50%
Adjusted Mean DCF	10.20%	10.94%	12.07%
Adjusted Median DCF	9.93%	10.78%	11.68%

Notes:
[1] Source: Bloomberg
[2] Source: Bloomberg. 90-day historical average for period ending July 31, 2009.
[3] Equals Col. [1]/Col. [2]
[4] Equals (Col. [1] x (1+(0.5 x Col. [9])))/Col. [2]
[5] Source: Bloomberg
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Source: Value Line
[9] Equals Midpoint of Mean(Cols. [5], [6], [7]) and Col. [8]
[10] Min. (Cols. [5] -- [8]) + (Col. [1] x (1 + (0.5 x Min. (Cols. [5] -- [8]))))/Col. [2]
[11] Col. [4] + Col. [9]
[12] Max. (Cols. [5] -- [8]) + (Col. [1] x (1 + (0.5 x Max. (Cols. [5] -- [8]))))/Col. [2]

90-DAY CONSTANT GROWTH DCF - U.S. ELECTRIC DISTRIBUTION COMPANIES

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Bloomberg Long-Term Growth	Thomson First Call Growth Estimate	Zacks Earnings Growth Estimate	Value Line Earnings Growth Estimate	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
U.S. ELECTRIC DISTRIBUTION COMPANIES													
CH Energy Group, Inc.	CHG	$2.16	$45.42	4.76%	4.79%	--	--	0.00%	3.00%	1.50%	4.76%	6.29%	7.83%
Consolidated Edison, Inc.	ED	$2.36	$37.27	6.33%	6.43%	4.48%	3.00%	4.30%	2.50%	3.21%	8.91%	9.65%	10.96%
DPL Inc.	DPL	$1.14	$22.70	5.02%	5.24%	10.00%	9.33%	7.40%	8.00%	8.46%	12.61%	13.69%	15.27%
Duke Energy Corporation	DUK	$0.96	$14.27	6.73%	6.88%	4.09%	3.67%	4.80%	5.00%	4.59%	10.52%	11.48%	11.90%
FPL Group, Inc.	FPL	$1.89	$55.00	3.44%	3.60%	9.19%	9.59%	9.00%	10.00%	9.63%	12.59%	13.23%	13.61%
MGE Energy, Inc.	MGEE	$1.45	$32.25	4.49%	4.61%	5.00%	5.00%	5.00%	6.00%	5.50%	9.60%	10.11%	10.62%
NSTAR	NST	$1.50	$30.96	4.84%	5.02%	6.33%	6.25%	6.40%	8.00%	7.16%	11.25%	12.18%	13.04%
Southern Company	SO	$1.75	$30.15	5.80%	5.95%	5.00%	4.83%	7.50%	4.50%	5.14%	10.43%	11.09%	13.52%
PROXY GROUP MEAN		$1.65	$33.50	5.18%	5.32%	6.30%	5.95%	5.55%	5.88%	5.65%	10.08%	10.96%	12.09%
PROXY GROUP MEDIAN		$1.63	$31.60	4.93%	5.13%	5.00%	5.00%	5.70%	5.50%	5.32%	10.48%	11.28%	12.47%

Flotation Cost Adjustment	0.50%	0.50%	0.50%
Adjusted Mean DCF	10.58%	11.46%	12.59%
Adjusted Median DCF	10.98%	11.78%	12.97%

Notes:
[1] Source: Bloomberg
[2] Source: Bloomberg. 90-day historical average for period ending July 31, 2009.
[3] Equals Col. [1]/Col. [2]
[4] Equals (Col. [1] x (1+(0.5 x Col. [9])))/Col. [2]
[5] Source: Bloomberg
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Source: Value Line
[9] Equals Midpoint of Mean(Cols. [5], [6], [7]) and Col. [8]
[10] Min. (Cols. [5] -- [8]) + (Col. [1] x (1 + (0.5 x Min. (Cols. [5] -- [8]))))/Col. [2]
[11] Col. [4] + Col. [9]
[12] Max. (Cols. [5] -- [8]) + (Col. [1] x (1 + (0.5 x Max. (Cols. [5] -- [8]))))/Col. [2]

90-DAY CONSTANT GROWTH DCF - CANADIAN UTILITIES

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Bloomberg Long-Term Growth	First Call Growth Estimate	Earnings Growth Estimate	Earnings Growth Estimate	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
CANADIAN UTILITIES													
Canadian Utilities	CU	$1.41	$36.14	3.90%	3.95%	2.70%	--	--	--	2.70%	6.65%	6.65%	6.65%
Emera	EMA	$1.01	$20.16	5.01%	5.16%	5.93%	--	--	--	5.93%	11.09%	11.09%	11.09%
Enbridge	ENB	$1.48	$38.27	3.87%	4.04%	12.14%	11.20%	8.00%	7.50%	8.97%	11.51%	13.01%	16.24%
Fortis Inc.	FTS	$1.04	$23.88	4.36%	4.50%	6.80%	--	--	--	6.80%	11.30%	11.30%	11.30%
TransCanada Corp.	TRP	$1.52	$31.03	4.90%	5.04%	4.30%	5.00%	5.00%	7.00%	5.88%	9.30%	10.93%	12.07%
PROXY GROUP MEAN		$1.29	$29.90	4.41%	4.54%	6.37%	8.10%	6.50%	7.25%	6.06%	9.97%	10.60%	11.47%
PROXY GROUP MEDIAN		$1.41	$31.03	4.36%	4.50%	5.93%	8.10%	6.50%	7.25%	5.93%	11.09%	11.09%	11.30%

Flotation Cost Adjustment	0.50%	0.50%	0.50%
Adjusted Mean DCF	10.47%	11.10%	11.97%
Adjusted Median DCF	11.59%	11.59%	11.80%

Notes:
[1] Source: Bloomberg
[2] Source: Bloomberg. 90-day historical average for period ending July 31, 2009.
[3] Equals Col. [1]/Col. [2]
[4] Equals (Col. [1] x (1+(0.5 x Col. [9])))/Col. [2]
[5] Source: Bloomberg
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Source: Value Line
[9] Equals Midpoint of Mean(Cols. [5], [6], [7]) and Col. [8]
[10] Min. (Cols. [5] -- [8]) + (Col. [1] x (1 + (0.5 x Min. (Cols. [5] -- [8]))))/Col. [2]
[11] Col. [4] + Col. [9]
[12] Max. (Cols. [5] -- [8]) + (Col. [1] x (1 + (0.5 x Max. (Cols. [5] -- [8]))))/Col. [2]

CAPITAL ASSET PRICING MODEL - U.S. NATURAL GAS DISTRIBUTION UTILITIES

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
		Adjusted Betas							
Company	Ticker	Bloomberg	Value Line	Mean Beta	30-Yr. Treasury Yield Forecast	Market Risk Premium	Low CAPM	Mean CAPM	High CAPM
U.S. NATURAL GAS DISTRIBUTION UTILITIES									
AGL Resources Inc.	AGL	0.78	0.75	0.76	4.77%	5.86%	9.17%	9.24%	9.31%
Piedmont Natural Gas Company, Inc.	PNY	0.70	0.65	0.68	4.77%	5.86%	8.58%	8.73%	8.87%
Sempra Energy	SRE	0.85	0.90	0.87	4.77%	5.86%	9.75%	9.90%	10.05%
South Jersey Industries, Inc.	SJI	0.66	0.65	0.65	4.77%	5.86%	8.58%	8.60%	8.61%
Southwest Gas Corporation	SWX	0.88	0.75	0.81	4.77%	5.86%	9.17%	9.54%	9.92%
Vectren Corporation	VVC	0.73	0.75	0.74	4.77%	5.86%	9.04%	9.10%	9.17%
PROXY GROUP MEAN		0.76	0.74	0.75	4.77%	5.86%	9.05%	9.18%	9.32%
PROXY GROUP MEDIAN		0.75	0.75	0.75	4.77%	5.86%	9.10%	9.17%	9.24%

	Low CAPM	Mean CAPM	High CAPM
Flotation Cost Adjustment	0.50%	0.50%	0.50%
Adjusted Mean CAPM	9.55%	9.68%	9.82%
Adjusted Median CAPM	9.60%	9.67%	9.74%

Notes:
[1] Source: Bloomberg
[2] Source: Value Line
[3] Equals mean of Cols. [1], [2]
[4] Equals average of 3- and 12-month out forecasts of 10-year government bond plus average spread between 10- and 30-year bond for July 2009.
Source: Consensus Forecasts and Bloomberg
[5] Equals mean of U.S. MRP (6.5%) and Canadian MRP (5.22%) per Morningstar / Ibbotson Associates
[6] Equals Col. [4] + (Min (Cols. [1], [2]) x Col. [5])
[7] Equals Col. [4] +(Col. [3] x Col. [5])
[8] Equals Col. [4] + (Max (Cols. [1], [2]) x Col. [5])

CAPITAL ASSET PRICING MODEL - U.S. ELECTRIC DISTRIBUTION COMPANIES

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
		Adjusted Betas							
Company	Ticker	Bloomberg	Value Line	Mean Beta	30-Yr. Treasury Yield Forecast	Market Risk Premium	Low CAPM	Mean CAPM	High CAPM
U.S. ELECTRIC DISTRIBUTION COMPANIES									
CH Energy Group, Inc.	CHG	0.73	0.65	0.69	4.77%	5.86%	8.58%	8.83%	9.07%
Consolidated Edison, Inc.	ED	0.65	0.65	0.65	4.77%	5.86%	8.58%	8.59%	8.60%
DPL Inc.	DPL	0.65	0.60	0.63	4.77%	5.86%	8.29%	8.45%	8.60%
Duke Energy Corporation	DUK	0.74	0.65	0.69	4.77%	5.86%	8.58%	8.83%	9.08%
FPL Group, Inc.	FPL	0.83	0.75	0.79	4.77%	5.86%	9.17%	9.40%	9.64%
MGE Energy, Inc.	MGEE	0.65	0.65	0.65	4.77%	5.86%	8.57%	8.57%	8.58%
NSTAR	NST	0.69	0.65	0.67	4.77%	5.86%	8.58%	8.69%	8.81%
Southern Company	SO	0.58	0.55	0.57	4.77%	5.86%	7.99%	8.08%	8.17%
PROXY GROUP MEAN		0.69	0.64	0.67	4.77%	5.86%	8.54%	8.68%	8.82%
PROXY GROUP MEDIAN		0.67	0.65	0.66	4.77%	5.86%	8.58%	8.64%	8.71%

	Low CAPM	Mean CAPM	High CAPM
Flotation Cost Adjustment	0.50%	0.50%	0.50%
Adjusted Mean CAPM	9.04%	9.18%	9.32%
Adjusted Median CAPM	9.08%	9.14%	9.21%

Notes:
[1] Source: Bloomberg
[2] Source: Value Line
[3] Equals mean of Cols. [1], [2]
[4] Equals average of 3- and 12-month out forecasts of 10-year government bond plus average spread between 10- and 30-year bond for July 2009.
Source: Consensus Forecasts and Bloomberg
[5] Equals mean of U.S. MRP (6.5%) and Canadian MRP (5.22%) per Morningstar / Ibbotson Associates
[6] Equals Col. [4] + (Min (Cols. [1], [2]) x Col. [5])
[7] Equals Col. [4] +(Col. [3] x Col. [5])
[8] Equals Col. [4] + (Max (Cols. [1], [2]) x Col. [5])

CAPITAL ASSET PRICING MODEL - CANADIAN UTILITIES

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
		Adjusted Betas							
Company	Ticker	Bloomberg	Value Line	Mean Beta	30-Yr. Treasury Yield Forecast	Market Risk Premium	Low CAPM	Mean CAPM	High CAPM
CANADIAN UTILITIES									
Canadian Utilities	CU	0.58	--	0.58	4.18%	5.86%	7.59%	7.59%	7.59%
Emera	EMA	0.59	--	0.59	4.18%	5.86%	7.61%	7.61%	7.61%
Enbridge	ENB	0.68	0.65	0.66	4.18%	5.86%	7.99%	8.07%	8.15%
Fortis Inc.	FTS	0.65	--	0.65	4.18%	5.86%	7.98%	7.98%	7.98%
TransCanada Corp.	TRP	0.63	0.85	0.74	4.18%	5.86%	7.85%	8.51%	9.16%
PROXY GROUP MEAN		0.62	0.75	0.64	4.18%	5.86%	7.80%	7.95%	8.10%
PROXY GROUP MEDIAN		0.63	0.75	0.65	4.18%	5.86%	7.85%	7.98%	7.98%

Flotation Cost Adjustment	0.50%	0.50%	0.50%
Adjusted Mean CAPM	8.30%	8.45%	8.60%
Adjusted Median CAPM	8.35%	8.48%	8.48%

Notes:
[1] Source: Bloomberg
[2] Source: Value Line
[3] Equals mean of Cols. [1], [2]
[4] Equals average of 3- and 12-month out forecasts of 10-year government bond plus average spread between 10- and 30-year bond for July 2009.
Source: Consensus Forecasts and Bloomberg
[5] Equals mean of U.S. MRP (6.5%) and Canadian MRP (5.22%) per Morningstar / Ibbotson Associates
[6] Equals Col. [4] + (Min (Cols. [1], [2]) x Col. [5])
[7] Equals Col. [4] +(Col. [3] x Col. [5])
[8] Equals Col. [4] + (Max (Cols. [1], [2]) x Col. [5])

EFFECT OF LEVERAGE OVER FLAT PORTION OF ATWACC CURVE- NATURAL GAS DISTRIBUTION GENERIC ROES AND CAPITAL STRUCTURE

	PROXY GROUP DATA AND ROE RESULTS	
1	Desired Interest Coverage	2.50X
2	Book Debt	55.34%
3	DCF ROE Result Before Flotation Adjustment	10.44%
4	CAPM Result Before Flotation Adjustment	9.18%
5	Average Recommendation before Financing Adjustment	9.81%
6	Embedded Debt Cost	6.42%
7	Proxy Group Average Levered Beta	0.75
8	Other Adjustments	0.00%
9	Adjustment for Financing Flexibility	0.50%
10	Average Proxy Group Tax Rate	39.34%
11	Average Ontario Federal and Provincial Tax Rate	33.00%
12	Average Proxy Group Risk Free Rate	4.77%
13	Canadian Risk Free Rate	4.18%

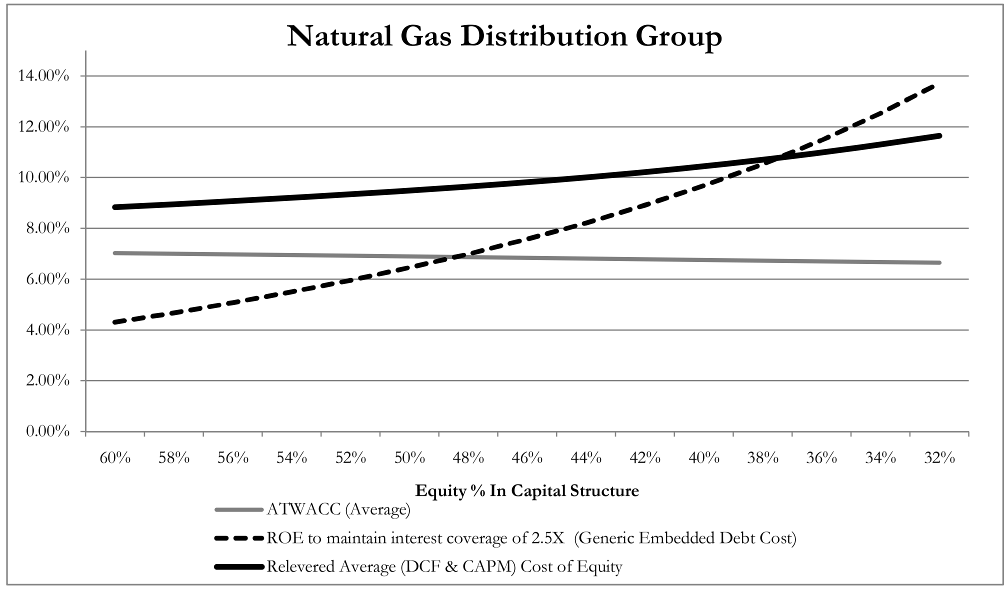
14

15 Hamada Formula:

$$\beta_{UL} = \frac{\beta_L}{1+(1-T_C)*(D/E)}$$

$$\beta_{RL} = \beta_{UL} + [1 + (1-T_C)*(D/E)]$$

β_{UL} = unlevered beta (at book cap structure)
β_{RL} = relevered beta (at book cap structure)
D = Debt Ratio
E = Equity Ratio
T_C = Corporate tax rate



16 CALCULATION OF UNLEVERED AND RELEVERED COST OF EQUITY USING THE HAMADA FORMULA:

17

	TARGET COMMON EQUITY RATIO	60.00%	58.00%	56.00%	54.00%	52.00%	50.00%	48.00%	46.00%	44.00%	42.00%	40.00%	38.00%	36.00%	34.00%	32.00%
18																
19																
20	Debt Cost	6.42%	6.42%	6.42%	6.42%	6.42%	6.42%	6.42%	6.42%	6.42%	6.42%	6.42%	6.42%	6.42%	6.42%	6.42%
21	After Tax Debt Cost	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%
22	Debt/Total Capital Ratio	55.34%	55.34%	55.34%	55.34%	55.34%	55.34%	55.34%	55.34%	55.34%	55.34%	55.34%	55.34%	55.34%	55.34%	55.34%
23	Proxy Group Mean Debt/Equity Ratio	123.92%	123.92%	123.92%	123.92%	123.92%	123.92%	123.92%	123.92%	123.92%	123.92%	123.92%	123.92%	123.92%	123.92%	123.92%
24	Combined Proxy Group Tax Rate	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%
25	Combined Canada Tax Rate	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%
26	Target Debt/Total Capital Ratio	40.00%	42.00%	44.00%	46.00%	48.00%	50.00%	52.00%	54.00%	56.00%	58.00%	60.00%	62.00%	64.00%	66.00%	68.00%
27	Target Debt/Equity Ratio	66.67%	72.41%	78.57%	85.19%	92.31%	100.00%	108.33%	117.39%	127.27%	138.10%	150.00%	163.16%	177.78%	194.12%	212.50%
28	Levered Beta	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
29	Risk Free Rate (U.S.)	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%
30	Risk Free Rate (Canada)	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%
31	Market Risk Premium (CAPM)	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%
32	Implied Market Risk Premium (DCF)	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%	7.53%
33	Implied Market Risk Premium (Average)	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%
34	Unlevered Beta	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
35	Relevered Beta	0.62	0.64	0.66	0.68	0.70	0.72	0.74	0.77	0.80	0.83	0.86	0.90	0.94	0.99	1.04
36	Adjustment for T&D Utilities from Proxy Group	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	Flotation/Financing Flexibility Adjustment	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
38	Relevered CAPM Cost of Equity	8.32%	8.42%	8.53%	8.64%	8.76%	8.89%	9.03%	9.18%	9.35%	9.53%	9.73%	9.95%	10.20%	10.48%	10.79%
39	Relevered DCF Cost of Equity	9.36%	9.49%	9.62%	9.76%	9.92%	10.08%	10.26%	10.46%	10.67%	10.91%	11.17%	11.45%	11.77%	12.12%	12.52%
40	Relevered Average (DCF & CAPM) Cost of Equity	8.84%	8.95%	9.07%	9.20%	9.34%	9.49%	9.65%	9.82%	10.01%	10.22%	10.45%	10.70%	10.98%	11.30%	11.65%
41	EBIT/Interest (Generic Embedded Debt Cost)	4.1x	3.9x	3.7x	3.5x	3.4x	3.2x	3.1x	2.9x	2.8x	2.7x	2.6x	2.5x	2.4x	2.4x	2.3x
42	ROE to maintain interest coverage of 2.5X (Generic Embedded Debt Cost)	4.30%	4.67%	5.07%	5.50%	5.96%	6.46%	6.99%	7.58%	8.22%	8.91%	9.68%	10.53%	11.48%	12.53%	13.72%
43	ATWACC Computed on Average (DCF and CAPM)	7.03%	7.00%	6.97%	6.95%	6.92%	6.90%	6.87%	6.84%	6.81%	6.79%	6.76%	6.73%	6.71%	6.68%	6.65%

EFFECT OF LEVERAGE OVER FLAT PORTION OF ATWACC CURVE- NATURAL GAS DISTRIBUTION GENERIC ROES AND CAPITAL STRUCTURE

EXPLANATION FOR CALCULATIONS

1	Appendix F, page F-20	1	Desired Interest Coverage
2	Exhibit Concentric-03, p. 1 of 3	2	Book Debt
3	Exhibit Concentric-05, p. 1 of 3	3	DCF ROE Result Before Flotation Adjustment
4	Exhibit Concentric-06, p. 1 of 3	4	CAPM Result Before Flotation Adjustment
5	Average Rows (3,4)	5	Average Recommendation before Financing Adjustment
6	Exhibit Concentric-04, Financial Profile	6	Embedded Debt Cost
7	Exhibit Concentric-06, p. 1 of 3	7	Proxy Group Average Levered Beta
8	N/A	8	Other Adjustments
9	Ontario Energy Board, *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, page 17	9	Adjustment for Financing Flexibility
10	Average U.S. Tax Rate	10	Average Proxy Group Tax Rate
11	Average Ontario Tax Rate	11	Average Ontario Federal and Provincial Tax Rate
12	Appendix F, page F-8	12	Average Proxy Group Risk Free Rate
13	Appendix F, page F-8	13	Canadian Risk Free Rate
14		14	
15	Hamada Formula: $\beta_{UL} = \dfrac{\beta_L}{1+(1-T_C)*(D/E)}$; $\beta_{RL} = \beta_{UL} + [1 + (1-T_C)*(D/E)]$; β_{UL} = unlevered beta (at book cap structure); β_{RL} = relevered beta (at book cap structure); D = Debt Ratio; E = Equity Ratio; T_C = Corporate tax rate	15	
16		16	
17		17	
18		18	
19		19	
20	Row 6	20	Debt Cost
21	Row 6 x (1 - Row 11)	21	After Tax Debt Cost
22	Row 2	22	Debt/Total Capital Ratio
23	Row 2 / (1-Row 2)	23	Proxy Group Mean Debt/Equity Ratio
24	Row 10	24	Combined Proxy Group Tax Rate
25	Row 11	25	Combined Canada Tax Rate
26		26	Target Debt/Total Capital Ratio
27	Row 26 / (1-Row 26)	27	Target Debt/Equity Ratio
28	Row 7	28	Levered Beta
29	Exhibit Concentric-06, p. 1 of 4	29	Risk Free Rate (U.S.)
30	Row 13	30	Risk Free Rate (Canada)
31	Exhibit Concentric-06, p. 1 of 4	31	Market Risk Premium (CAPM)
32	(Row 3 - Row 12) / Row 7	32	Implied Market Risk Premium (DCF)
33	(Row 5 - Row 12) / Row 7	33	Implied Market Risk Premium (Average)
34	Row 28/ (1+(1 - Row 24)x Row 23)	34	Unlevered Beta
35	Row 35 + (1 + (1-Row 25) x Row 27)	35	Relevered Beta
36	Row 8	36	Adjustment for T&D Utilities from Proxy Group
37	Row 9	37	Flotation/Financing Flexibility Adjustment
38	Row 30 + (Row 35 x Row 31) + Row 36 + Row 37	38	Relevered CAPM Cost of Equity
39	Row 30 + (Row 35 x Row 32) + Row 36 + Row 37	39	Relevered DCF Cost of Equity
40	Row 30 + (Row 35 x Row 33) + Row 36 + Row 37	40	Relevered Average (DCF & CAPM) Cost of Equity
41	[((1-Row 26) x Row 40) x (1/(1 - Row 25)) + (Row 20 x Row 26)] / (Row 20 x Row 26)	41	EBIT/Interest (Generic Embedded Debt Cost)
42	[(Row 1 x (Row 20 x Row 26) - (Row 20 x Row 26)) x (1 - Row 25)] / (1 - Row 26)	42	ROE to maintain interest coverage of X (Generic Embedded Debt Cost)
43	[Row 40 x (1-Row 26)] + [Row 26 x Row 20 X (1- Row 25)]	43	ATWACC Computed on Average (DCF and CAPM)

Note: It is our intention to illustrate the effect of leverage over the critical range where the ATWACC is relatively flat, and not to address increases in debt costs associated with increased leverage, i.e. debt costs are held constant over the range.

EFFECT OF LEVERAGE OVER FLAT PORTION OF ATWACC CURVE- ELECTRIC DISTRIBUTION GENERIC ROES AND CAPITAL STRUCTURE

PROXY GROUP DATA AND ROE RESULTS

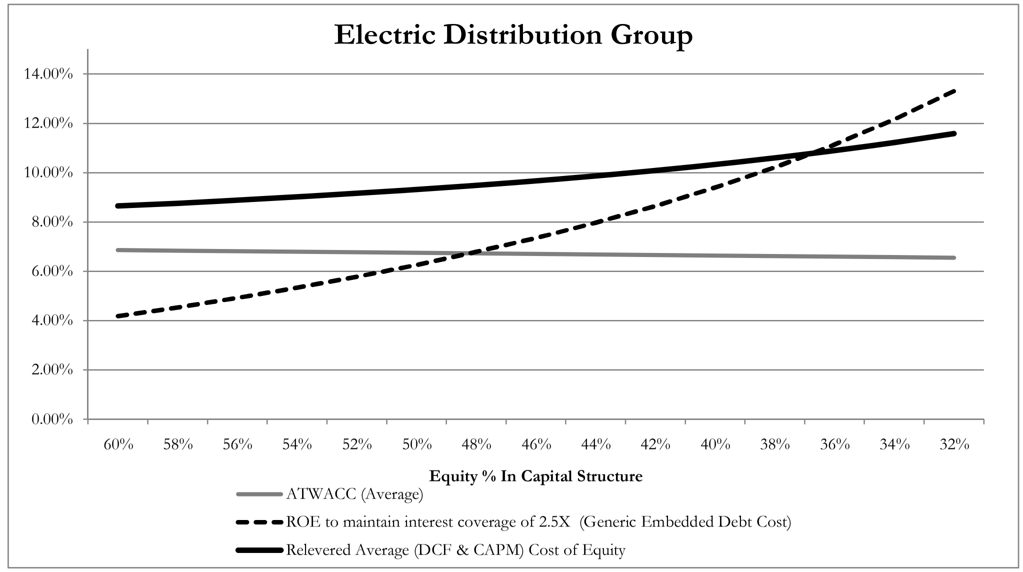
1	Desired Interest Coverage	2.50X
2	Book Debt	52.66%
3	DCF ROE Result Before Flotation Adjustment	10.96%
4	CAPM Result Before Flotation Adjustment	8.68%
5	Average Recommendation before Financing Adjustment	9.82%
6	Embedded Debt Cost	6.23%
7	Proxy Group Average Levered Beta	0.67
8	Adjustment for T&D Utilities from Proxy Group	-0.40%
9	Adjustment for Financing Flexibility	0.50%
10	Average Proxy Group Tax Rate	39.34%
11	Average Ontario Federal and Provincial Tax Rate	33.00%
12	Average Proxy Group Risk Free Rate	4.77%
13	Canadian Risk Free Rate	4.18%
14		

15 Hamada Formula:

$$\beta_{UL} = \frac{\beta_L}{1+(1-T_C)*(D/E)}$$

$$\beta_{RL} = \beta_{UL} + [1 + (1-T_C)*(D/E)]$$

β_{UL} = unlevered beta (at book cap structure)
β_{RL} = relevered beta (at book cap structure)
D = Debt Ratio
E = Equity Ratio
T_C = Corporate tax rate



16 CALCULATION OF UNLEVERED AND RELEVERED COST OF EQUITY USING THE HAMADA FORMULA:
17

#	TARGET COMMON EQUITY RATIO	60.00%	58.00%	56.00%	54.00%	52.00%	50.00%	48.00%	46.00%	44.00%	42.00%	40.00%	38.00%	36.00%	34.00%	32.00%
18																
19																
20	Debt Cost	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%	6.23%
21	After Tax Debt Cost	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%
22	Debt/Total Capital Ratio	52.66%	52.66%	52.66%	52.66%	52.66%	52.66%	52.66%	52.66%	52.66%	52.66%	52.66%	52.66%	52.66%	52.66%	52.66%
23	Proxy Group Mean Debt/Equity Ratio	111.22%	111.22%	111.22%	111.22%	111.22%	111.22%	111.22%	111.22%	111.22%	111.22%	111.22%	111.22%	111.22%	111.22%	111.22%
24	Combined Proxy Group Tax Rate	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%	39.34%
25	Combined Canada Tax Rate	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%	33.00%
26	Target Debt/Total Capital Ratio	40.00%	42.00%	44.00%	46.00%	48.00%	50.00%	52.00%	54.00%	56.00%	58.00%	60.00%	62.00%	64.00%	66.00%	68.00%
27	Target Debt/Equity Ratio	66.67%	72.41%	78.57%	85.19%	92.31%	100.00%	108.33%	117.39%	127.27%	138.10%	150.00%	163.16%	177.78%	194.12%	212.50%
28	Levered Beta	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67	0.67
29	Risk Free Rate (U.S.)	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%	4.77%
30	Risk Free Rate (Canada)	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%	4.18%
31	Market Risk Premium (CAPM)	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%
32	Implied Market Risk Premium (DCF)	9.28%	9.28%	9.28%	9.28%	9.28%	9.28%	9.28%	9.28%	9.28%	9.28%	9.28%	9.28%	9.28%	9.28%	9.28%
33	Implied Market Risk Premium (Average)	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%	7.57%
34	Unlevered Beta	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
35	Relevered Beta	0.58	0.59	0.61	0.63	0.64	0.67	0.69	0.71	0.74	0.77	0.80	0.83	0.87	0.92	0.97
36	Adjustment for T&D Utilities from Proxy Group	-0.40%	-0.40%	-0.40%	-0.40%	-0.40%	-0.40%	-0.40%	-0.40%	-0.40%	-0.40%	-0.40%	-0.40%	-0.40%	-0.40%	-0.40%
37	Flotation/Financing Flexibility Adjustment	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
38	Relevered CAPM Cost of Equity	7.66%	7.75%	7.85%	7.95%	8.06%	8.18%	8.31%	8.45%	8.61%	8.78%	8.96%	9.17%	9.40%	9.65%	9.94%
39	Relevered DCF Cost of Equity	9.63%	9.77%	9.93%	10.09%	10.27%	10.46%	10.66%	10.89%	11.13%	11.40%	11.70%	12.02%	12.39%	12.79%	13.25%
40	Relevered Average (DCF & CAPM) Cost of Equity	8.65%	8.76%	8.89%	9.02%	9.16%	9.32%	9.49%	9.67%	9.87%	10.09%	10.33%	10.60%	10.89%	11.22%	11.59%
41	EBIT/Interest (Generic Embedded Debt Cost)	4.1x	3.9x	3.7x	3.5x	3.4x	3.2x	3.1x	3.0x	2.9x	2.7x	2.6x	2.6x	2.5x	2.4x	2.3x
42	ROE to maintain interest coverage of 2.5X (Generic Embedded Debt Cost)	4.18%	4.54%	4.92%	5.34%	5.78%	6.26%	6.78%	7.35%	7.97%	8.65%	9.39%	10.22%	11.13%	12.16%	13.31%
43	ATWACC Computed on Average (DCF and CAPM)	6.86%	6.83%	6.82%	6.79%	6.77%	6.75%	6.73%	6.70%	6.68%	6.66%	6.64%	6.62%	6.59%	6.57%	6.55%

EFFECT OF LEVERAGE OVER FLAT PORTION OF ATWACC CURVE- ELECTRIC DISTRIBUTION GENERIC ROES AND CAPITAL STRUCTURE

EXPLANATION FOR CALCULATIONS

1	Appendix F, page F-20	1	Desired Interest Coverage
2	Exhibit Concentric-03, p. 2 of 3	2	Book Debt
3	Exhibit Concentric-05, p. 2 of 3	3	DCF ROE Result Before Flotation Adjustment
4	Exhibit Concentric-06, p. 2 of 3	4	CAPM Result Before Flotation Adjustment
5	Average Rows (3,4)	5	Average Recommendation before Financing Adjustment
6	Exhibit Concentric-04, Financial Profile	6	Embedded Debt Cost
7	Exhibit Concentric-06, p. 2 of 3	7	Proxy Group Average Levered Beta
8	Appendix C, page C-4	8	Adjustment for T&D Utilities from Proxy Group
9	Ontario Energy Board, *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, page 17	9	Adjustment for Financing Flexibility
10	Average U.S. Tax Rate	10	Average Proxy Group Tax Rate
11	Average Ontario Tax Rate	11	Average Ontario Federal and Provincial Tax Rate
12	Appendix F, page F-8	12	Average Proxy Group Risk Free Rate
13	Appendix F, page F-8	13	Canadian Risk Free Rate
14		14	
15	Hamada Formula: (see below)	15	

Hamada Formula:

$$\beta_{UL} = \frac{\beta_L}{1+(1-T_C)*(D/E)}$$

$$\beta_{RL} = \beta_{UL} + [1 + (1-T_C)*(D/E)]$$

β_{UL} = unlevered beta (at book cap structure)
β_{RL} = relevered beta (at book cap structure)
D = Debt Ratio
E = Equity Ratio
T_C = Corporate tax rate

16		16	
17		17	
18		18	
19		19	
20	Row 6	20	Debt Cost
21	Row 6 x (1 - Row 11)	21	After Tax Debt Cost
22	Row 2	22	Debt/Total Capital Ratio
23	Row 2 / (1-Row 2)	23	Proxy Group Mean Debt/Equity Ratio
24	Row 10	24	Combined Proxy Group Tax Rate
25	Row 11	25	Combined Canada Tax Rate
26		26	Target Debt/Total Capital Ratio
27	Row 26 / (1-Row 26)	27	Target Debt/Equity Ratio
28	Row 7	28	Levered Beta
29	Exhibit Concentric-06, p.2 of 4	29	Risk Free Rate (U.S.)
30	Row 13	30	Risk Free Rate (Canada)
31	Exhibit Concentric-06, p.2 of 4	31	Market Risk Premium (CAPM)
32	(Row 3 - Row 12) / Row 7	32	Implied Market Risk Premium (DCF)
33	(Row 5 - Row 12) / Row 7	33	Implied Market Risk Premium (Average)
34	Row 28/ (1+(1 - Row 24)x Row 23)	34	Unlevered Beta
35	Row 35 + (1 + (1-Row 25) x Row 27)	35	Relevered Beta
36	Row 8	36	Adjustment for T&D Utilities from Proxy Group
37	Row 9	37	Flotation/Financing Flexibility Adjustment
38	Row 30 + (Row 35 x Row 31) + Row 36 + Row 37	38	Relevered CAPM Cost of Equity
39	Row 30 + (Row 35 x Row 32) + Row 36 + Row 37	39	Relevered DCF Cost of Equity
40	Row 30 + (Row 35 x Row 33) + Row 36 + Row 37	40	Relevered Average (DCF & CAPM) Cost of Equity
41	[((1-Row 26) x Row 40) x (1/(1 - Row 25)) + (Row 20 x Row 26)] / (Row 20 x Row 26)	41	EBIT/Interest (Generic Embedded Debt Cost)
42	[(Row 1 x (Row 20 x Row 26) - (Row 20 x Row 26)) x (1 - Row 25)] / (1 - Row 26)	42	ROE to maintain interest coverage of X (Generic Embedded Debt Cost)
43	[Row 40 x (1-Row 26)] + [Row 26 x Row 20 X (1- Row 25)]	43	ATWACC Computed on Average (DCF and CAPM)

Note: It is our intention to illustrate the effect of leverage over the critical range where the ATWACC is relatively flat, and not to address increases in debt costs associated with increased leverage, i.e. debt costs are held constant over the range.

Proxy Group Operating Companies	Parent Company Ticker	[1] Net Generation (MWh)	[2] Total Sources of Energy (MWh)	[3] Net Generation / Total Sources of Energy
Alabama Power Company	SO	69,989,917	79,005,475	88.59%
Central Hudson Gas & Electric Corp	CHG	82,405	4,020,163	2.05%
Consolidated Edison Company of New York, Inc.	ED	2,857,711	26,722,523	10.69%
Dayton Power and Light Company	DPL	15,510,403	18,158,138	85.42%
Duke Energy Carolinas, LLC	DUK	85,846,145	90,870,546	94.47%
Duke Energy Indiana, Inc.	DUK	34,851,344	37,922,298	91.90%
Duke Energy Kentucky, Inc.	DUK	3,998,650	4,796,358	83.37%
Duke Energy Ohio, Inc.	DUK	20,146,509	33,296,617	60.51%
Florida Power & Light Company	FPL	95,005,811	112,862,779	84.18%
Georgia Power Company	SO	80,817,132	103,228,117	78.29%
Gulf Power Company	SO	14,761,691	15,919,737	92.73%
Madison Gas and Electric Company	MGEE	2,123,050	3,907,190	54.34%
Mississippi Power Company	SO	14,323,994	16,312,090	87.81%
NSTAR Electric Company [4]	NST	12,688,959	25,773,767	0.00%
Orange and Rockland Utilities, Inc.	ED	0	4,542,809	0.00%
Pike County Light & Power Company	ED	0	n/a	0.00%
Rockland Electric Company	ED	0	1,765,667	0.00%

Average % Generation For Proxy Group Utilities	
CHG	2.05%
DPL	85.42%
DUK	82.56%
ED	2.67%
FPL	84.18%
MGEE	54.34%
NST	0.00%
SO	86.85%
Average	**49.76%**

Notes:
[1] Source: FERC Form 1, page 401a
[2] Source: FERC Form 1, page 401a
[3] Equals Col. [1] / Col. [2]
[4] 12,688,959 MWh is competitive supplier loads, net generation = 0 MWh

REGRESSION RESULTS

Regression Statistics	
Multiple R	0.612
R Square	0.375
Adjusted R Square	0.371
Standard Error	0.567
Observations	620

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	118.682	29.671	92.205	0.000
Residual	615	197.900	0.322		
Total	619	316.583			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	7.634	0.197	38.717	0.000	7.246	8.021	7.246	8.021
U.S. Government 30-year Bond	0.428	0.027	15.864	0.000	0.375	0.481	0.375	0.481
Moody's Utility A-rated Spread	0.310	0.049	6.344	0.000	0.214	0.406	0.214	0.406
% Generation	0.008	0.001	7.335	0.000	0.006	0.010	0.006	0.010
Electric = 0; Gas = 1	0.384	0.074	5.203	0.000	0.239	0.529	0.239	0.529

Adjustment for T&D Utilities:	-0.40%	[1]

Notes:

[1] Equals Average % Generation for Proxy Group Utilities x Coefficient of "% Generation"

CAPITAL MARKETS ISSUES
RELATING TO THE
ONTARIO ENERGY BOARD'S
RETURN on EQUITY FORMULA

Prepared by:

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September 2009

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SECTION 1

INTRODUCTION AND BACKGROUND

This submission to the Ontario Energy Board (the "OEB" or the "Board") addresses the on-going concerns of debt and equity market participants regarding the method by which the Fair Return and the rate of return on common equity (the "ROE") for utilities operating in Ontario are established. In particular, the determination of the ROE in Ontario is based on a formulaic approach which annually adjusts a base ROE, usually awarded by a regulatory panel following a generic or cost of service hearing, by a specified proportion of the difference between the forecast yield of a long term Canada bond (maturity of 30 years) during the utility's test year to the forecast yield of the same bond in the base year. In Ontario and other Canadian jurisdictions, the proportion is currently set at 75%, such that for each 1% decline (or increase) of the forecast 30 year Long Canada bond yield for the utility's test year versus the forecast 30 year Long Canada yield in the base year, the ROE awarded for the base year is reduced (or increased) by 0.75% to determine the test year ROE.

The formulaic approach to the determination of ROEs has been employed by the OEB since 1997 for gas utilities and since 1999 for electric distribution utilities. The British Columbia Utility Commission (the "BCUC") and the National Energy Board (the "NEB") had adopted similar formulas in 1994 while the Alberta Energy and Utilities Board (the "AEUB") adopted a formulaic approach in 2004.

Initially the formulaic approach was viewed as a positive step forward in the regulatory process as the ROE setting process became more timely, more predictable, more transparent and the regulatory burden (both the cost and the amount of management time) associated with annual cost of capital reviews was significantly reduced. The re-regulation of the sector in Ontario by the OEB in 1999 to include more than 250 municipally owned electric distribution utilities also added support for the use of a formula and generalized set of decision making rules to set appropriate returns and capital structures for cost of capital purposes.

The use of essentially similar formulas in each of the major regulatory jurisdictions across Canada (the OEB, NEB, BCUC and AEUB) brought a measure of consistency and comparability to rates of return awarded to utilities which had not existed previously and was viewed favourably by participants in the capital markets.

In 2006, the OEB reviewed the application of the formulaic approach and capital structure decision making for electric distribution companies during EB-2006-0088, following Board Staff recommendations to alter the formula and decision making rules with respect to capital structure to assist in streamlining the regulatory process. Upon review, the OEB concluded, among other things, that while there should be no change in the original ROE methodology adopted in 1999, all electric distribution companies should be deemed to have a common equity base of 40%.

The ROE formula was re-based to reflect changes in interest rates between 1999 and 2006 and became:

ROEt = 9.35% + .75 x (YLTCt – 5.50%); where

ROEt is the return on common equity for test year t; and

YLTCt is the forecast yield for long term Canada bonds in test year t.

In 2009, electric distribution companies in Ontario subject to rate rebasing are allowed to earn a return on common equity of 8.01% on a 40% common equity base. The gas utilities are allowed to earn a slightly higher ROE on a somewhat smaller common equity base. For example, Enbridge is allowed to earn a return on common equity of 8.39% on a common equity base of 36%.

Problems with the formulaic approach became apparent a few years following its introduction, as ROEs awarded to gas utilities in Ontario began to decline at a faster rate than the ROEs of utilities in the United States having generally similar risk profiles. Compounding this problem, the total regulated return on capital (the “Fair Return”) in the United States provided greater financial integrity to the utility due to the fact that, relative to Canadian utilities, a larger common equity base is usually accepted for rate making purposes. In the United States, the larger common equity base earned a higher return on equity than utilities having similar risk profiles in Canada. The OEB attempted to ascertain the extent of differences in ROEs awarded and the common equity capitalizations for utilities in Canada and United States in 2007 by retaining Concentric

Energy Advisors Inc. ("Concentric") to study the situation. Concentric's report on their findings is posted on the OEB's website at:

http://www.oeb.gov.on.ca/documents/industryrelations/keyinitiatives/research/research_ROE_20070614.pdf

The report concludes that since the implementation of a formulaic approach in 1997, ROEs for Ontario gas distribution utilities have been generally lower than those for utilities in the United States by approximately 150 to 200 basis points. Prior to 1997, awarded returns in Ontario were at least at parity and sometimes greater than common equity returns awarded in the U.S. Additionally, the Canadian sample of utilities considered in the Concentric study had been awarded an average common equity percentage within their regulated capital structure of 37.45% while the U.S. sample of utilities had an average common equity ratio of 46.44% within their regulated capital structure. The report also concluded that, taken as a whole, U.S. gas utilities are not demonstrably riskier than Canadian gas utilities implying that the 150 to 200 basis point differential which had developed since 1997 is not appropriate.

Recent disruptions in the capital markets and the financial parameters produced by the formulaic model have somewhat exacerbated the rate differential problem between utilities in Ontario and the U.S. and reduced the credibility of the Board's ROE process further, in the view of financial analysts and capital market participants. Following the major credit crisis experienced in global capital markets during 2008/2009 and a more bearish view for growth in the global economy due to the lack of credit availability and other factors, the yield on federal government debt declined to approximate 65 year lows.

This reflected a ”flight to quality” by lenders in the face of the credit crisis, as Government of Canada bonds are the most liquid bonds available in the domestic marketplace and have virtually no default risk. Additional demand for Government of Canada bonds due to the credit crisis added impetus to already declining yields throughout the 1995 to 2008 period reflecting the improving financial position of the federal government, which was the result of the federal government paying down debt, growth in the Canadian economy and achieving annual budget surpluses. Even with the decline of long term Canada yields, the required yield for ‘A’ rated utility debt increased by 100 to 150 basis points as the credit spread between utility debt and Government of Canada bonds increased materially. The cost of attracting additional common equity increased as common and preferred dividend yields increased and the stock market in Canada and elsewhere sold off substantially. Notwithstanding these increases, the rate of return on common equity proposed by the ROE formula for 2009 was 8.01% compared to 8.57% for 2008 while the cost of long term utility debt for 2009 was to be 7.62% versus a forecast cost of 6.10% in 2008. The resulting spread between the yield on long term utility debt and the rate of return on utility common equity declined from 247 basis points in 2008 to a mere 39 basis points in 2009. The proposed reduction of the ROE in an environment of significant increases in the cost of new common equity and the material decline in the spread between the utility ROE and the utility debt rate immediately caused concern in the debt and equity capital markets as the integrity of utility debt and equity capital in Ontario continued its downward decline which had begun in 1997.

On March 16, 2009, the OEB initiated a consultative process to help it determine whether current economic and financial market conditions warranted an adjustment to any of the Cost of Capital parameter values (i.e., the return on common equity, long term debt rate, and/or short term debt rate) set out in the Board's letter of February 24, 2009. On June 18, 2009, the OEB issued its determination that the cost of capital parameter values for 2009 rates should not change from previously announced values and advised stakeholders that it is proceeding with a review of its policy regarding the cost of capital. The OEB anticipated that any changes to the policy made as a result of this review will apply to the setting of rates for the 2010 rate year.

The OEB's review of its policy regarding the cost of capital is entirely consistent with the actions of other regulatory boards using a formula to adjust ROEs. For example, the NEB waived the use of its ROE formula derived in Decision RH-2-94 for Trans Quebec and Maritime Pipe Line to derive rates for 2007 and 2008 and based its determination on an after tax weighted average cost of capital ("ATWACC") approach which gave rise to higher ROEs for the two years than the RH-2-94 formula would have provided. The Alberta Public Utilities Commission is currently reaching the end of a generic ROE hearing process which has essentially become a review of the reasonableness of its formula. The BCUC is reviewing the capital structure and ROE of Terasen Gas, the "benchmark low risk utility" in British Columbia and this review is focused on the reasonableness of the formula in use in that jurisdiction.

Section 2 of this submission provides an executive summary of the conclusion reached.

Section 3 outlines the major concerns or issues that capital market participants have with the OEB ROE setting formula and year-to-year ROE adjustment mechanism.

Section 4 of this submission responds to the OEB's issues list from a capital markets perspective.

The appendix contains my qualifications to address these issues.

SECTION 2

EXECUTIVE SUMMARY

The review of the Board's policy regarding the cost of capital, the Fair Return Standard and the current ROE formula and adjustment mechanism is very timely given economic and capital markets developments since the adoption by the OEB of the equity risk premium approach in 1997. The Board's objective is to consistently meet the Fair Return standard with respect to the return on common equity, long and short term debt costs and capital structures awarded to gas and electric distribution utilities operating in Ontario. In addition, the level of activity in the annual regulatory calendar in Ontario demands that all stakeholders in the process must be on the lookout for new approaches that are more streamlined, more transparent and more reasonable in light of long term economic and capital markets developments.

Lenders and equity investors in Canada view the Board's proceeding and other similar proceedings before the NEB, BCUC and the AEUB as potentially watershed events which could define their investment programs in the future.

Currently and for the foreseeable future, there will be an ample supply of investment opportunities in domestic and international utility-like infrastructure projects. These projects offer lenders strong credit metrics, utility-like credit ratings, indirect government support and equivalent or higher returns than utility bonds. The same projects offer equity investors a diverse portfolio of long term "necessary" assets, indirectly supported by governments, synergistic business partnerships with domestic and international private sector developers and operators and returns which exceed those available in the Ontario utility sector.

Tax changes in 2005 and continuing market integration have allowed Canadian lenders and equity investors to participate, to a much greater extent, in the financing of utility and infrastructure assets in foreign jurisdictions. It is anticipated that this investment trend will continue as Canadian investors become more comfortable operating in such jurisdictions.

The implications of these developments are that Ontario based gas and electric distribution utilities face a much more competitive environment in which to attract debt and equity funds to finance capital expenditures. To be able to attract funds on reasonable terms, Ontario based utilities should have internationally competitive credit metrics, such as earnings and cash flow coverage of interest obligations and cash flow to total debt obligations, adequate equity bases and competitive rates of return on common equity. The Board's ROE setting methodology impacts the foregoing financial results directly.

With regard to the determination of an appropriate ROE for utility purposes, the perception of the long Canada bond yield has changed significantly since the equity risk premium approach was derived in the 1990s. At that time, the yield on such bonds was not a pure "risk free rate" but included additional compensation required by foreign investors for Canada's somewhat more tenuous financial position and weaker currency. Fortunately, due to strong economic growth and prudent financial management in the intervening period, Canada is now viewed more positively in international capital markets. This change in perception as well as an effective debt management program have removed, for the most part, the historic yield premium and brought 30 year Canada bond yields to approximate 65 year lows. In 2006, the ROE formula was re-calibrated when yields on long Canada bonds were expected to be 5.50%. Such yields are now less that 4.00%.

Achieved investor returns have been driven down by so-called "exuberant" market conditions. According to central bankers and other market participants, investors have been willing to accept too much investment risk for too little return. The market correction in the last year represents the end of this anomaly. Unfortunately investors' willingness to accept inadequate returns in the past may have been considered in the re-calibration of the equity risk premium in 2006.

The reliability of the year-to-year adjustment mechanism, based solely on expected changes in long term Canada bond yields, has also been called into question by a major study, commissioned by this Board, of Canada and U.S. awarded utility returns. The recent decision by the National Energy Board (RH-1-2008), one of the first jurisdictions to adopt the ERP methodology and formulaic approach to setting the ROE in which, the NEB set aside the use of only Government of Canada bond yields to determine pipeline ROEs, chose a different methodology which provided higher ROEs and also endorsed the review and consideration of the financial performance of U.S. based pipelines and utilities as they represent comparable risk opportunities for Canadian investors.

There have been significant concerns and commentary in the capital markets that the Board’s current formula and methodology does not meet the Fair Return standard and does not preserve the financial integrity of Ontario based utilities.

SECTION 3

DISCUSSION OF CAPITAL MARKETS ISSUES

The OEB announced the initiation of a review of its policy regarding cost of capital in a letter dated February 24, 2009 while at the same time announcing the financial parameters generated by the Board's ROE annual adjustment mechanism and short and long term debt costs for rate making purposes. In a subsequent letter dated March 16, 2009, the Board requested stakeholder input on whether the cost of capital parameters should be altered due to then current economic and financial market conditions. The OEB noted that for test years 2008 and 2009 the spread between the allowed return on utility equity and the cost allowed for utility long term debt had declined from 247 basis points (2.47%) in 2008 to only 39 basis points (0.39%) in 2009. The Board's request for comments was met with responses from eighteen groups, only two of which were active participants in Canadian and international capital markets. This low level of response by the financial community could be construed by some as a lack of interest or concern regarding the OEB's policy regarding the determination of an appropriate ROE for rate making purposes. This conclusion would be completely false in my experience. Market participants have commented for some time on the deficiencies of formula derived ROEs and as early as the summer of 2008, analysts had anticipated ROE reasonableness issues arising in 2009 and 2010. Market participants typically focus on the outcome of the ROE mechanism rather than the process used to establish it.

The following discussion includes the major capital market issues associated with the performance and application of the OEB's equity risk premium approach and the use of a formula to derive year-to-year changes in the awarded return on common equity for gas and electric utilities operating in Ontario:

1. Debt and equity analysts, credit rating agencies and institutional lenders and investors believe that the rate setting methodology is functioning improperly (or is "broken", as characterized by one equity analyst), in that, the financial integrity of Ontario based utilities has been eroded over an extended period of time reflecting the combination of inadequate returns on common equity and lower than appropriate awarded common equity components of their capital structure, given their risk profile. In 2009, this problem was exacerbated as the ROE formula produced a reduction in the 2008 rate of return on common equity while capital markets throughout much of 2008 and the first quarter of 2009 have required higher returns on all types of publicly traded corporate securities;

2. The increased debt interest rates, lower equity valuations and more difficult financing environment recently experienced in Canada and abroad has made it more difficult for utilities to attract capital on reasonable terms;

3. Utilities in Canada must compete for debt and equity funds with a much broader array of possible issuers than ever before. These issuers include domestic and international infrastructure projects (power projects, hospitals, airports, highways and bridges) and foreign utilities which may benefit from alternate forms of regulation or stronger financial performance than those based in Ontario. Recent tax changes allow Canadian institutional and retail lenders and investors to greatly expand their purchase of foreign securities without restriction or cost. In order to retain access to funds in this more competitive environment for debt and equity, Canadian utilities must maintain or

improve their financial integrity by achieving returns on common equity equivalent to those earned by U. S. based utilities of similar risk, as well as achieving stronger credit metrics such as higher earnings and cash flow coverage of interest obligations and thicker common equity bases. Unfortunately, the current ROE formula produces returns 150 to 200 basis points below similar U.S. utility returns and the awarded return is often earned on smaller common equity base. Many infrastructure projects offer credit ratings equivalent to those of the utilities, indirect government support and higher returns relative to utilities.

4. The capital market disruptions experienced in 2008 were the final stage of an extended period during which capital had been available at very low costs. These lower costs were not sustainable in the long term and did not reflect the risks associated with the investment or the financial leverage employed to enhance investor returns. Now that the equity capital markets have experienced a major correction as investors have realized the low rates of return previously earned are inadequate, awarded utility returns should not be subjected to a form of double jeopardy, that is, being awarded low rates of return on common equity during the 1997 to 2007 period, reflecting investors' investment exuberance and, going forward, to have ROEs reduced due to the major portfolio losses and lower realized returns experienced by investors in 2008 and 2009;

5. The concept of using only the change in forecast long Canada bond yields to annually adjust utility ROE levels has been rejected by debt and equity analysts as well as the NEB. Such an adjustment is extremely unlikely to reflect the increase (or decrease) of utility business or financial risk or provide the necessary increase (or decrease) to the base ROE to compensate for the changed circumstances;

6. The initially accepted level of the utility equity risk premium in Ontario of 375 to 400 basis points may have been too low to be sustainable over the long term. In the 1990s when the equity risk premium model was first employed, the long term Government of Canada bond was certainly not viewed as a “risk free security” by international lenders who determined the bond’s yield at the margin. The yield reflected Canada’s relatively high debt to GDP ratio, its weak currency and the risk of a bond rating downgrade by international markets. The equity risk premium determined in the regulatory process was likely understated due to the higher Government of Canada bond yield required to attract foreign bond buyers. In current circumstances, long term Government of Canada yields are approaching 65 year lows and reflect upward price pressure from the recent flight to quality caused by the corporate credit crisis, the stronger position of the Canadian dollar and the improved financial performance of the federal government. As a result, the original 375 to 400 basis point equity risk premium used for ROE purposes likely understates the required long term equity risk premium. The premium currently in use should be fully reviewed to determine whether it has been set at the appropriate long run value sufficient to attract additional utility equity investment; and,

7. Rather than relying exclusively on the results of a single, possibly incorrectly specified ERP formula, capital market participants would prefer the application by the OEB of “informed judgment” to a much broader database of relevant information to determine the final selection of an appropriate ROE and capital structure for utilities under its jurisdiction. Generic reviews of the selected methodology and its appropriateness should be undertaken at least every five years. A review of the financial

parameters produced by the methodology should be carried out annually to consider the reasonableness of the parameter values and to ensure they are directionally consistent with developments in the capital markets.

Responses from capital market participants to the OEB's March 16 consultative process were unequivocal in their conclusion that the proposed return on equity component was too low and this resulted from a miscalibrated equity risk premium methodology. Debt and equity research reports reported that the methodology used by the NEB and provincial regulators was directionally incorrect, that is, while corporate costs of capital were increasing in the marketplace, utility debt credit spreads and preferred share dividend yield spreads were increasing, the methodology suggested that the utility common equity cost of common equity capital should decline from 8.57% in 2008 to 8.01% in 2009.

The views of these capital markets participants were supported and re-enforced by comments made in published reports by various equity analysts from BMO Capital Markets and RBC Capital Markets and by bond rating agency, DBRS.

BMO Capital Markets has commented since 2006 that the formula produced ROEs were too low and likely did not meet the fair return standard (see Karen Taylor's Presentation to the 2006 OEA Conference on September 13, 2006). Not surprisingly, BMO viewed the recent NEB decision to set aside the RH-2-94 formula as a positive from a corporate debt and equity perspective, as it increased the Trans Quebec and Maritime Pipeline's ("TQM") return on equity to 9.75% on 40% deemed common equity or 11.6% on 30% deemed equity, which is significantly above the 8.71% on a 30% common equity base, TQM would have obtained under the RH-2-94 formula for 2008. In BMO's view, the ATWACC methodology takes into account changes in economic and industry conditions and does not depend solely on the forecast of the Government of Canada bond yields. Furthermore, the increase in ROE should strengthen the financial profile of companies operating under this methodology over the medium term, as cash flow generation should improve (See BMO Capital Markets report entitled "ROE Potentially Headed Higher in Canada" dated March 23, 2009 by George Lazarevski).

On January 16th, 2009, RBC Capital Markets published an equity research report by Robert Kwan, CFA (entitled "Allowed ROEs: The Formula is Broken, but Will Regulators Fix It?") that stated the ROE formulas were "broken" in that they were producing declining ROEs in 2009 and 2010 while corporate debt yields and equity risk premiums were rising. The analyst recommended that from a risk-reward perspective, investment strategies should focus on utilities with the least exposure to regulation by a formula.

In a published newsletter (DBRS Canada Newsletter, dated May 6, 2009), DBRS reviewed NEB decision RH-1-2008 in which the NEB set aside its Multi-Pipeline Cost of Capital Decision (RH-2-94) which uses a formula very similar to the OEB's formula to determine rates of return on common equity for TQM for 2007 and 2008. DBRS pointed out that if the methodology of the decision was applied broadly, it would have a positive financial impact on NEB regulated oil and gas pipelines and on electric and natural gas distribution utilities, if implemented at the provincial level. DBRS stated that the RH-2-94 formula, along with declining interest rates, had resulted in weakened credit ratios and lower returns on equity capital compared with other investment alternatives for pipeline owners.

These comments from capital market participants mirrored those of the NEB in its decision RH-1-2008. The board concluded that 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. The NEB also concluded that there had been significant changes in economic and capital market conditions which cast doubt on the reasonableness of the RH-2-94 formula including the globalization of capital markets, the much higher level of competition for funds, the decline in Canada's debt to GDP ratio and exchange rate movements. The NEB acknowledged that competition for funds is a major issue and that pipeline and utility companies operating in the U.S. can act as useful proxies for investment opportunities available in the global marketplace.

Although Decision RH-1-2008 related only to TQM, the NEB has subsequently initiated a general process to review the RH-2-94 Decision and the reasonableness of results from the current formula.

With regard to the competition for and allocation of common equity funds, this is a significant issue for Ontario based utilities. Were it not for the these utilities' obligation to provide safe, reliable service, it is likely that investors or corporate decision makers would allocate fewer equity dollars to utilities operating in Ontario due to the relatively low rates of return and smaller common equity bases allowed for regulatory purposes. From a shareholder value point of view, management will only invest in the common equity of the Ontario utility up to the common equity base permitted by the OEB and then only to the extent that the investment opportunity at least returns the utility's after tax weighted average cost of capital. For example, a parent utility holding company may reject capital expenditures in the Ontario utility to pursue higher return projects available in other parts of its consolidated business. Unfortunately, this is not something that observers can directly witness as these decisions are usually confidential. Investors would, of course, demand that corporations act in their best interests by pursuing comparable risk, higher return opportunities. As noted by DBRS in its report, opportunities for utility holding companies to invest in contracted or regulated opportunities in other jurisdictions at higher returns on equity are available.

The corporate debt market continues to purchase long term utility debt notwithstanding the eroding rate of return and associated lower earnings and cash flow coverage of interest obligations. While the debt market remained open to utility issuers during the recent credit crisis, the cost of utility debt escalated sharply as utility credit spreads over long term Canada bonds for A rated long term debentures increased from approximately 90 to 100 basis points in 2005 and 2006, to approximately 95 to 130 basis points in 2007, to approximately 130 to 350 basis points in 2008 and peaked in January 2009 at approximately 340 to 350 basis points. Furthermore, the impact of the increase in corporate bond spreads was muted by a decline in Canada bond yields during the same period.

There is increased competition for longer term debt and equity funding for major infrastructure and public/private partnership financing initiatives. This type of financing supports long term necessary infrastructure assets (hospitals, roads, airports, other transportation assets and services, court houses, and/or power projects). Such projects usually have the indirect support of a provincial government (in Ontario, for example, Infrastructure Ontario plays a major role in structuring the province's indirect support of such initiatives to achieve a business and financing risk transfer to the private sector) and normally includes the operation of the facilities by an experienced private sector developer/operator. These types of projects normally achieve credit ratings that are reasonably similar to utility credit ratings (usually an 'A' credit rating), are funded on a long term basis similar to most utility borrowers and usually provide a higher credit spread over Government of Canada bonds to lenders, in order to attract a significant volume of new funding. Equity finance is provided by the private sector operators, major pension funds and other institutional investors at returns in excess of those available under the ROE formula. It is reasonable to anticipate that this form of competition for debt and equity funds will continue to grow, given government focus on needed infrastructure improvements and the recent use of infrastructure spending to stimulate the economy. To remain competitive for funds, utilities must retain their credit ratings by maintaining or preferably enhancing their credit metrics such as the utility's earnings and cash flow coverage of interest obligations and its debt to total capital ratio. These improvements are likely only to be achieved through the award of an increased return on common equity and a larger common equity base for rate making purposes.

The globalization of Canadian capital markets and the removal of various personal and institutional restrictions on foreign investment have caused the Canadian and international capital markets to become substantially more integrated than in the past. This has also increased the level of competition for debt and equity funds.

Canadian institutional and retail investors (through their RSP accounts) have been freed from restrictions regarding their ability to invest in foreign debt and equity securities and domestic limited partnerships and income trusts as a result of pension fund legislation passed in 2005.

Foreign property restrictions for Canadian pension funds, pension real estate and investment corporations, deferred income plans (including individual registered retirement savings plans) and other tax-exempt entities were introduced in 1971. Such restrictions limited the amounts of "foreign property" these tax exempt plans could hold. Foreign property generally consists of shares, units and debt issued by non-resident entities, investments in most trusts and investments in most partnerships. The foreign property limit, which was originally set at 10%, was raised to 20% in 1994 and then to 30% in 2001. The Income Tax Act (Canada) provided that tax exempt plans holding assets in excess of these foreign property limits were subject to a 1% per month penalty tax.

Following the changes in 2005, many of Canada's largest institutional investors could invest in foreign securities without limit and, as a result, have become major players on international stock markets and non-Canadian private equity situations. Investors, such as the Ontario Teachers Pension Fund ("Teachers"), The Ontario Municipal Employee Retirement System ("OMERS"), The British Columbia Investment Management Corporation ("BCIMC"), the Canada Pension Plan Investment Board ("CPP") and

Alberta Investment Management ("AIM"), have bid for and won private equity opportunities in regulated utilities and utility-like but non-regulated situations in the U.S. and Europe. OMERS has announced its intention to diversify into private equity to reduce its exposure to the volatility of public stock markets and to increase its exposure to long term investments in utility-like infrastructure projects. To date, many of these infrastructure investment opportunities have been outside of Canada and have included assets such as gas and electricity transmission, gas and electricity distribution systems in the United States, Europe and South America, airports in the United Kingdom, regulated drinking water and sewage water utilities in the U.K., container terminals in the United States and Canada and the Ontario land registry system.

Retail investors were also granted much greater freedom to invest their self managed retirement savings plans in foreign equities, limited partnerships and income trusts under the same legislation.

Greater competition has also emerged in the Canadian bond market as foreign issuers increased their issuance activity following the removal of limitations on foreign investments. The market in Canada for the new issuance of foreign bonds and debentures (so called "Maple Bonds") has grown rapidly reflecting the Canadians lenders desire to diversify their portfolios with new issuers and to achieve higher returns with similar or, in some cases, stronger credit metrics than those available from domestic issuers. Foreign issuance in the Canadian bond market has represented approximately 18.9% of the domestic new issue market from 2005 to 2008.

In 2007, foreign issuance in the Canadian domestic bond market peaked at approximately 29%. The market was driven by Canadian lenders willingness to invest in these issues to broaden the diversification of their fixed income portfolios with new foreign names and by attractive Canadian dollar/U.S. dollar swap spreads which made the transaction economic for treasurers of foreign issuers to issue in Canadian dollars.

Sun Life noted in its submission to the Board dated April 17, 2009, that the “period of several years prior to the current financial crisis should also not be considered normal market conditions. Capital was much more available than it normally would be, was available more widely for companies with high leverage, and at much more attractive rates than would be true in a more normal lending environment.” This implies that the previous review and calibration of the OEB’s formula in 2006 may have taken place at a time of non-sustainable liquidity and included an equity risk premium that had been estimated at a lower than long run level due to “exuberant market conditions” at the time.

Some participants in the capital markets believe that credit was too available and costs of capital were too low. Central bankers are now looking for methods to reduce the occurrence of asset bubbles by developing methods to subdue the so called “market exuberance” which makes credit readily available at low cost, encourages excessive leverage and appears to lower required rates of return for investors. Mark Carney, the Governor of the Bank of Canada recently described (August 22, 2009) capital market conditions experienced over the past few years as follows:

“Consider three states of the world. In the normal state, financial agents balance macroeconomic and idiosyncratic risks in their investing, lending, and financing decisions. In the exuberant state, agents become complacent about macroeconomic risks and seek to exploit more idiosyncratic or obscure opportunities.[5] In the panicked state, macroeconomic risks dominate and all idiosyncratic risks are shunned. The normal state is just that, normal. The other two extremes are the tails that we have just lived through.

A prolonged, benign macroeconomic environment can encourage the transition from normal to exuberant states. As we have all just been reminded at great cost, low, stable, and predictable inflation and low variability in activity – especially when associated with exceptionally low and stable interest rates – can breed complacency among financial market participants as risk taking adapts to the perceived new equilibrium.[6] Indeed, risk appears to be at its greatest when measures of it are at their lowest. Low variability of inflation and output (reduces current financial Value at Risk (“VaR”)) and encourages greater risk taking (on a forward VaR basis). Investors stretch from liquid to less-liquid markets. In parallel, low and stable interest rates promote larger asset-liability mismatches across credit and currency markets. These tendencies are particularly marked if there is a perceived certainty about the stability of low interest rates.[7] “

5. They do so within a perceived risk budget. The actual risk budget has, of course, grown.

6. Either perceptions of risk or risk preferences could change. In the former case, complacency about actual risks can mean taking greater risks within the same risk budget.

7. See Diamond and Rajan (2005).

In summary, from a capital markets perspective, there are a number of worrisome issues regarding the derivation and year-to-year operation of the formula. These issues are:

(i) the derivation of the initial base equity risk premium of approximately 3.85% (including the addition of 0.50% for floatation and transaction costs) over the forecast long Canada bond yield;

(ii) the level of sensitivity of market required returns on common equity to changes in the credit markets and corporate yield spreads;

(iii) the reasonableness of increasing or decreasing utility ROEs based solely on the increase or decrease of the long term Canada bond yield; and,

(iv) the frequency of the in-depth review of the ROE formula and year-to-year adjustment mechanism to ensure that they are operating correctly and providing a reasonable approximation of the utilities actual cost of common equity capital.

As to the level of the initial equity risk premium imbedded in the model, EB-2006-0088 determined an appropriate equity risk premium over long term Canada bonds to be 3.85% including 0.5% for floatation and transaction costs. This conclusion was not based on the conclusion of an extensive generic hearing but rather on views expressed but not tested in a very much less formal Technical Conference convened to discuss revisions to the ERP formula methodology put forward by Board Staff. This premium of 3.85% looks rather slim to equity market participants who, in the past year, have had the opportunity to buy dividend re-set preferred shares (for these shares, the dividend coupon is re-set every five years to a fixed spread, established at the outset of the transaction above the yield on the benchmark 5 year Government of Canada bond) issued by many of Canada’s largest most highly rated banks and insurance companies at spreads of up 400 to 425 basis points. For example, the Royal Bank of Canada completed an offering of Series AX dividend re-set preferred shares on April 22, 2009 at an initial dividend coupon of 6.10% and a re-set spread of 413 basis points above the 5 year Canada bond. This indicates that the base utility equity risk premium of approximately 3.85% should be reviewed as it may not be appropriate and may not be at a level that provides a just and reasonable return to the utilities in the longer term.

As to the sensitivity of ROEs to changes in the credit markets, the Concentric report indicated in 2007 that a difference of between 150 and 200 basis points in Ontario versus U.S. ROEs had opened up since the introduction of the model in 1997. While U.S. ROEs have declined, Canadian ROEs have done so much more rapidly. This suggests that the current 75% sensitivity factor may be too large or that, as the NEB concluded, changes in the forecast yield of long term Canada bonds failed to capture changes in the utilities risk profile and that over time, this omission has the potential to grow and raise further doubts regarding the accuracy of the formula.

SECTION 4

SPECIFIC ISSUES RAISED BY THE OEB

In a letter dated July 30, 2009, the OEB noted that the application of the Fair Return Standard would be central to the stakeholder consultation. The Fair Return Standard (the "FRS") specifies that a fair or reasonable return on capital should accomplish all of the following objectives:

- Be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
- Maintain the financial integrity of the regulated enterprise (the financial integrity standard); and,
- Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

In advance of addressing the OEB's specific issues, I would like to point out that, in my experience, financial analysts, investors, credit rating agencies and lenders concentrate on the result of the application of these standards rather than the specific formulae used to obtain the results. Investors and lenders recognize that each model employed in the regulatory process as well as each database relied upon to determine an appropriate result for the comparable earnings standard, the financial integrity standard or the capital attraction standard has its own strengths and deficiencies. In their view, no one formula or approach provides the definitive answer, each different approach brings greater insight and adds value to the process. Investors and lenders recognize that the more extensive the database upon which the final decision regarding a Fair Return is made, the better the decision is likely to be. Capital market participants also expect that regulators will exercise “informed judgment” to determine an appropriate return such that the three standards are met.

The following provides a capital markets’ perspective on the issues raised by the OEB in its letter of July 30:

1. What method(s)/test(s) might the Board formally consider to determine whether the return on capital meets: (i) the comparable investment standard; (ii) the financial integrity standard; and (iii) the capital attraction standard?

A: Financial market participants would prefer the OEB to consider all relevant information prior to determining an appropriate base ROE and capital structure for utilities under its jurisdiction. A generic hearing should be held from time-to-time to recalibrate the fair return and the return on equity adjustment mechanism based on then current economic and financial market conditions. The Board should consider trends in the creditworthiness of Ontario utilities and utilities in Canada and the U.S. which are competing for debt and equity funds, the extent of the competition for funds from other sources including domestic and international infrastructure projects, the ability of Ontario based utilities to attract funds on reasonable terms and results derived from a comparable earnings test (based on book returns on common equity of comparable risk companies), a discounted cash flow analysis (market required rates of return of utilities and similar risk competitive companies), a modified equity risk premium model and other more complex models (for example, a multi-variable analysis). The review of this data will allow the OEB to render an informed judgment on the appropriate levels for the ROE and capital structure of utilities operating in Ontario. Capital market participants recognize that each of the foregoing methodologies have different limitations and no one test provides "the answer"; however, in their view, the Board should consider all relevant data and such data should be weighed by the OEB prior to the final determination of the base ROE, capital structure and cost of capital. Since no one model is without limitation, it is prudent for the Board to consider the results of multiple methodologies to establish a fair ROE.

2. Is the current deemed capital structure appropriate? If not, what alternative(s) might the Board consider?

A: The view in the market is that, given the low level of the awarded ROEs produced by the current formula, the common equity bases deemed for, in particular, the gas distribution utilities are too low. The resulting return on capital, earnings and cash flow coverage of interest obligations and cash flow to total debt ratios are at the low end of acceptable range for lenders and credit rating agencies. The utilities' financial integrity and ability to attract new debt capital are usually supported by the expectation that the regulatory environment will continue to be supportive, that the utility will not be pushed to the lowest possible level of its creditworthiness (i.e. being forced to borrow in the short term market, if the long term market is not available due to credit concerns or new issue restrictions) and that the regulatory process will address the financial issues of the utilities in a timely and responsive matter. The increases in the equity bases of Enbridge and Toronto Hydro have been viewed by the capital markets as being necessary to offset the declining ROEs that have been awarded over the past few years.

The NEB did not explicitly deem a capital structure for TQM in Decision RH-1-2008. Credit rating agencies and sophisticated lenders would view any move to reduce utility equity thickness from current levels as a negative event for the creditworthiness of the utility and such a move could lead to credit rating reduction.

Credit rating agencies, debt and equity analysts found the RH-1-2008 decision to be a credit positive for TQM notwithstanding that a specific common equity thickness was not deemed. Lenders and investors reacted positively to the fact that TQM was awarded a 6.4% ATWACC for each of 2007 and 2008, compared to an ATWACC of 5.5% (an increase of approximately 16%) that would have been produced if the NEB had employed the ROE formula from RH-2-94 and a previously deemed 30% common equity base.

The foregoing indicates that investors and lenders do not demand a deemed capital structure so long as the results of the regulatory process are supportive of the utility's financial integrity and its ability to attract new capital. If the OEB opts for a new formula that requires a common equity base percentage to determine the fair return, it should look to the trends in the electricity and gas distribution sector in Canada and in the U.S. to set an appropriate level, much as it did in 2006 proceeding relating to the appropriate equity base for Toronto Hydro.

3. Should the approach to setting cost of capital parameter values differ depending on whether a distributor finances through the capital markets or through government lending such as Infrastructure Ontario or through bank lending? If so, what would be the implications, if any, of doing so?

A: No. The same regulatory approach should be used for all distributors independent of sources of financing and their ownership. This approach would create a level playing field for all distribution companies within their respective sectors and would result in all distribution companies achieving roughly similar credit metrics and roughly similar returns on equity. These similarities may support greater merger and amalgamation activity in the electric distribution sector.

If bank lending is employed by the utility, the long term debt cost would be replaced with a cost of short term or longer tem bank debt as appropriate. If Infrastructure Ontario loans are used, the cost should reflect corporate funding costs for the appropriate term of the debt rather than the Ontario funding cost.

4. Does the analysis in the Concentric Report provide a reasonable foundation for satisfying the comparable investment standard?

A: No. The report provides an ex poste analysis of the ROEs awarded under two quite different forms of regulation. The report indicates that the results of a case-by-case regulatory review of utilities generally produces a higher rate of return on common equity for utilities of approximately the same investment risk than the formula derived ROEs used in Ontario. The report also concludes that utilities in the U.S. generally have larger common equity bases than gas utilities in Ontario and, as a result, their return on capital would be greater than returns available in Ontario. The findings of the report infer that depending on only the modified equity risk premium model and the year-to-year ROE adjustment mechanism to determine an appropriate return on common equity produce markedly lower returns than the constant application of inform judgment by experienced regulatory panels.

To meet the comparable investment standard, the model should consider expected future returns from competitive non-regulated companies. These returns should be compared with the trend of utility returns to ensure that both are directionally consistent.

5. If not, what might the Board use as a comparator group?

A: The purpose of regulation is to produce returns on capital and common equity that approximate those available to unregulated competitive businesses of similar risk in the economy. In this context, risk includes both business and financial risk. This suggests that the returns earned by a group of good quality companies having somewhat greater business risk characteristics and somewhat lesser financial risk, in the form of reduced debt leverage, similar credit ratings and relatively stable financial performance over the course of a business cycle would represent the best comparator group to gas and electric distribution companies. Furthermore, given the continuing integration of North American economies and financial markets, the hollowing out of the Canadian corporate sector due to cross border merger and acquisition activity and the changes to investment restrictions in Canada, the Board should build a framework which considers returns achieved by U.S. utilities and other competitive firms as appropriate comparators.

6. **Were the Board to only consider the use of Canadian utilities as a comparator group, is there an issue with circularity, given that the ROEs of these**

utilities are, and have been established by a mechanism similar to that currently used by the Board?

A: Yes.

8. Should the ERP approach be reset given that when the formula was first established when the reference bond rate was 8.75%?

A: Long Canada bond yields are now at approximately 3.8% to 4%. Recent financial parameters produced by the ROE formula that have been judged to be directionally incorrect by the capital markets. The Concentric study commissioned by the OEB suggests that, since 1997, awarded rates of return from the formula have been 150 to 200 basis points below those awarded to utilities of similar risk in the United States, It would be entirely appropriate to reset the inputs to the model, including the initial equity risk premium (currently set at 3.85%), and the sensitivity of the utility ROE to changes in the credit markets (currently set at .75).

9. **Should the ERP approach be reset on a regular basis (e.g. every 4 or 5 years) to mitigate the issues described in the 1997 Compendium?**

A: Yes; however, the exercise should not be viewed as just resetting an interest rate. The review should be complete in terms of determining if the equity risk premium remains appropriate, if the sensitivity of ROEs to changes in the credit markets appears to be accurate and if the fair return standard has been and is being met. If there is a shift by other regulatory bodies away from the ROE formula and toward a different approach that produces superior results under the fair return standard, this new approach should be considered by the OEB. The review period for Ontario's formula should be in the range of 3 to 5 years. Given the identified difficulties of the existing formula, participants in the capital markets would support an early review of a new or replacement formula (say, 3 years) to ensure that the ROE mechanism has been re-calibrated correctly and the formula is producing fair returns.

10. How might the Board address the potential issues arising from the application of the current methodology as a single, point-in-time calculation?

A: The capital markets view the current formula as being confiscatory to the utilities. The equity risk premium is likely too low, the sensitivity to changes in the credit markets is likely too high and changes in the Government of Canada bond yield are not reflective of changes in the utility's risk profile. These are the issues which must be addressed. If these issues are not addressed, providers of funds will simply choose to invest in assets located in other more progressive regulatory jurisdictions.

11. How should the Board establish the initial ROE for the purposes of resetting the methodology?

A: The Board should establish the initial ROE by way of a generic hearing which should review the ERP methodology to determine whether it is reasonable and consider other methodologies which might replace the existing methodology. The inputs to the selected methodology should be reviewed, including the appropriate level for the equity risk premium under current and prospective circumstances, the appropriate sensitivities of the ROE to changes in credit market and stock market returns and the most appropriate base for the model (i.e. corporate bond yields rather than Government of Canada bond yields).

12. Is the government (of Canada) bond yield the appropriate base upon which to begin the return on equity calculation?

A: The Government of Canada bond yield is one of a number of possible bases upon which to build a modified equity risk premium model. Yields of 'A' rated corporate utility bonds could also serve as a base for the ERP model. The ERP model provides one estimate of the current cost of common equity and this estimate should be considered as one input into the determination of the return on equity awarded a utility from a broader database of facts and information. Other inputs would include results from the comparable earnings test, the trend and level of DCFs for utilities and other unregulated, comparable companies as well as the outlook for the economy and capital market conditions.

13. What is the relationship between corporate bond yields and the corporate cost of equity? Is this relationship sustainable?

A: Corporate bond yields are determined by two factors in the marketplace. The first factor is the yield on the benchmark Canada bond, having a similar term to maturity. The second factor is the credit spread over the Canada bond required by the lenders to attract their funds. The relationship between corporate debt and benchmark Canadian bonds can shift over time and through business cycles. There is a clear tendency for the cost of common equity to increase or decrease with similar movements in corporate debt spreads. As perceived investment risk increases, the credit spread will increase as will the cost of common equity capital. Because credit spreads can increase for reasons other than an increase in the risk of the issuer, for example, when a flight to quality changes the corporate debt spread environment, it is reasonable to expect that the relationship between the cost of equity and the cost of corporate debt is stronger than that between the cost of equity and the yield on benchmark long term Canada bonds.

14. Does the current approach used by the Board to calculate the ERP remain appropriate? If not, how should the ERP be calculated?

A: Many participants in the capital markets believe that the ERP approach combined with the year-to-year adjustment mechanism are no longer appropriate methods to determine the fair return on utility assets in Ontario. Analysts, credit rating agencies, lenders and investors believe returns are too low and the financial integrity of the utilities has been eroded since 1997. Virtually all of these participants concur with the findings of the NEB in Decision RH-1-2008 that movements in the yields of long Canada bonds do not capture the circumstances or risks of the utility sector. These same participants support the NEB's move to improve the fairness of returns awarded to utilities compared to the existing formulaic approach. I believe capital markets would also prefer that the NEB and provincial regulators fully adopt similar methods of regulation such that comparability, transparency and predictability, within the utility sector, are largely maintained.

The initial values for the cost of capital would be determined in a generic hearing with input from the gas distribution utilities, electric distribution utilities and electric transmission utilities to determine whether one set of cost of capital parameters could accommodate the circumstances of each of these sectors. The cost of capital parameter values for a particular sector would then be established by the OEB after considering and applying informed judgment to consider current and prospective economic and capital markets conditions, comparable earnings, DCF tests, equity risk premium model results and all other tests and information that are relevant.

15. Should the Board adopt a dead band? If so, what should the range of the dead band be?

A: Participants in the capital markets view the adoption of a dead band as primarily administrative fine tuning which should be applied to a regulatory system which has proven itself with a history of fair and reasonable returns. Given the identified problematic issues with the current formula and its annual adjustment mechanism, instituting a dead band mechanism would not be viewed as a priority by the capital markets.

If adopted, the range of the dead bands would depend on the type of measure being calculated. For example, the range of variation of an ATWACC should be smaller than the range of variation of an ROE. The most important element from the capital markets perspective would be the adoption of a regulatory system that can produce a consistently fair and reasonable return over time and under different economic and capital market conditions.

16. Should the Board adopt trigger mechanism(s)? If so, how often should the Board review the methodology?

A: The OEB should review the financial parameters produced by the formula annually prior to the formal release of the results. The review should address why the parameters have increased (or decreased) from the previous year. These results should be compared with other relatively visible economic and capital market indicators to ensure that any proposed changes in the regulatory parameters are directionally correct. If the proposed financial parameters are questioned by the OEB, the rates from the previous year should be continued until all issues have been resolved to the Board's satisfaction.

The methodology should be reviewed every three to five years depending on the history of annual reviews.

17. What is the appropriate test(s) to ensure the FRS is met (e.g. corroborating results for reasonableness relative to other benchmarks or through other methods)?

A: The Board should corroborate the results by reviewing capital market indicators, corporate utility debt rates in Canada and the US, litigated ROE results from both Canada and the US (i.e. not formula produced returns). To establish the initial FRS, the Board should use all information and methodologies available to it, including the ERP, DCF, and Comparable Earnings methodologies. This approach recognizes that no individual methodology is flawless, but each has something unique to offer, and that in combination, use of all methodologies plus informed judgment provided by the regulator produces superior, more robust results. It also recognizes that this is, generally speaking, how capital markets determine and view the fair return.

18. **What information might the Board need to definitively determine that market conditions are having an effect on the variables used by the Board's cost of capital methodology?**

A: Regulators should be aware of the general trend of relevant financial parameters including returns on assets and returns on common equity for regulated industries on a continent wide basis to ensure that changes to its own financial parameters are directionally consistent. Other indicators would include the trend of credit spreads on 10 and 30 year utility debt obligations and credit rating reports relating to any upgrades, downgrades or the support provided by the regulatory system (Moody's assigns a rating to the level of regulatory support in different jurisdictions). Negative trends in these indicators should be subjected to further research to determine if the deterioration is utility specific or whether it's a systemic problem applicable to the entire regulatory regime.

19. Should the Board consider monitoring indicators like these on an on-going basis to test the reasonableness of the results of its cost of capital methodology?

A: Yes, however, it should be noted that the privately owned utilities operating in Ontario do not directly access the common equity market. Declining equity valuations and difficulty attracting equity capital for the Ontario utilities may be hidden by the utility's publicly traded parent company's ability to invest in similar risk, higher return domestic and/or international projects featuring less onerous regulatory conditions or the fact that the parent has effectively diversified its regulatory risk by operating in a number of different jurisdictions each using a somewhat different regulatory approach.

20. What other key metrics used by financial market participants to determine whether financial market conditions are or are not "normal" might the Board consider?

A: If such metrics existed, investors would use them to buy during normal periods and sell during periods of positive market exuberance. The recent disruptions in the capital markets suggest that metrics indicating what is "normal" are not particularly informative. An informed, balanced view of activities taking place in the capital markets is often provided by central banks such as the Bank of Canada or the U.S. Federal Reserve Board.

Appendix A

**Qualifications of
Donald A. Carmichael**

My name is Donald A. Carmichael. I live in Toronto, Ontario where I am a financial consultant and advisor. Prior to becoming a financial consultant, I worked in the investment banking industry for more than 30 years with Scotia Capital Inc., Richardson Greenshields Limited and McLeod Young Weir Limited. My work was principally focused on natural gas transmission and distribution companies as well as electricity generation, transmission and distribution companies in both the public and private sectors. I was responsible for advising investment banking clients on the appropriate terms and pricing of debt and equity securities, providing strategic advice regarding mergers and acquisitions and executing business on behalf of some of the firms' most significant clients. This included advising both governments and corporations on strategic, regulatory and financing issues. I frequently participated in the marketing of debt and equity transactions to institutional investors, on behalf of my clients. I had extensive interaction with representatives of such lenders and investors in respect of the business profile of the issuer and the pricing of the issue. My activities in Ontario include debt, preferred and/or common equity financing for The Consumers Gas Company Ltd., Union Gas Limited, Hydro One Inc. Toronto Hydro Corporation and the valuation of Consumers Gas and Union Gas for acquisition purposes.

Since forming my consulting and advisory business, I have advised the following clients:

- In 2006, I appeared on behalf of the Coalition of Large Electricity Distributors (a group consisting of Toronto Hydro, Mississauga Hydro, Horizon Utilities, PowerStream Utilities, Ottawa Hydro and Veridian Corporation) before a Technical conference organized by the Ontario Energy Board (the "OEB") to discuss new processes to regulate Ontario's 90 local electricity distribution companies in a more streamlined fashion. I commented on the potential capital markets reaction to the OEB's proposals to streamline the determination of the ROE as well as necessary levels of equity capital to finance utility investment.
- In 2007, I co-authored an expert report to the Nuclear Waste Management Organization regarding its long term funding program for the storage of nuclear waste produced by nuclear power reactors operating in Canada. In addition, I assisted Ontario Power Generation Inc. ("OPG") in negotiating the financial parameters of a long term power purchase agreement between OPG and the Ontario Power Authority. I advised Toronto Hydro Corporation regarding the financing of certain non-regulated activities through subsidiary companies on a limited or non-recourse basis.
- During 2008, I advised OPG on various regulatory strategies relating to its initial application to the OEB regarding the company's regulated nuclear and hydraulic generating assets. I provided an opinion to OPG's senior management team as to whether the applied for rate increase was reasonable

in light of the risks which the regulated operations of the Company face and to provide on-going strategic and tactical input.

- In 2009, I have submitted testimony to the British Columbia Utility Commission regarding the reasonableness of its ROE formula on behalf of Terasen Gas Inc.

I received my education at The University of Waterloo where I obtained an Honours Bachelor of Mathematics degree and at the Rotman School of Business at the University of Toronto where I achieved a Master of Business Administration with specializations in Finance and Operations Research.

Over the course of my career, I have appeared before the National Energy Board (Interprovincial Pipe Lines Limited and Trans Mountain Pipe Line Inc.), the Canadian Radio-television and Telecommunications Commission (the BC Telephone Company Limited, Telesat and Teleglobe), the Alberta Energy and Utilities Board (AltaLink LLP), the OEB (Union Gas Inc., Ontario Hydro, Coalition of Large Distributors), the New Brunswick Public Utilities Board (New Brunswick Power Corporation) and the Board of Commissioners of Public Utilities of Newfoundland (Newfoundland and Labrador Hydro).